TECHNOLOGY CHOICE AND POLICY CHOICE FOR CO2 CONTROL OF JAPAN'S UTILITIES

by

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M.E., Chemical Engineering, Kyoto University, 1988
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ABSTRACT

Nuclear power is the main focus for resource-poor Japan's CO2 emissions control because it is the least-cost technology for power generation and, consequently, of CO2 emissions control. Cost-effectiveness is an essential guideline for technology choice, although not necessarily an optimal guideline. The lead-time for nuclear power plant development is approaching 25 years and could present a significant risk, obstructing the implementation of the CO2 controls agreed to in Kyoto in 1997.

This thesis reconsiders technology and policy choice for CO2 emissions control. It begins by estimating the risks inherent in the volatile lead-time that is delaying CO2 emission control. Although Japan plans to build 20 nuclear power plants by 2010, it is demonstrated that this plan involves considerable risk. In addition, this work sheds light on the trade-off between cost-effectiveness and risk, and demonstrates how technology portfolios which combine nuclear power and low-risk technologies, such as wind power, reduce this risk. Scenario and sensitivity analysis incorporate uncertainties in the lead-time and the costs of power generation into technology choice.

Finally, this thesis investigates policy choice. The ongoing deregulation of the utilities has the potential to conflict with effective CO2 emissions control. By analyzing the interaction between two policies—CO2 control and deregulation—this work demonstrates that a tradable certificate system of carbon-free power generation can resolve potential conflicts and, in fact, harmonize them. Because of the great gap in cost between nuclear power and other, low-risk technologies, economic forces such as CO2 emissions penalties have little practical effect on technology choice. In contrast, the tradable certificate system ensures workable technology portfolios and simultaneously reduces the cost of power generation and CO2 emissions control through market-competition.

Thesis Supervisor: Professor Henry D. Jacoby
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1. INTRODUCTION

The control of carbon dioxide (CO2) emissions is of concern to governments, industries, and the public, all of whom might be affected by the likely climate change produced by the burning of fossil fuel. In response to the international concern over global climate change, the Conference of the Parties to the United Nations Framework Convention on Climate Change (COP3) was held in Kyoto in December 1997. As a result of this meeting, Japan and other developed countries agreed to legally binding targets for CO2 emissions. Regardless of international agreements, however, the most important aspect of emission control remains the effective enforcement by each government of their own domestic policies.

For Japan's domestic policy, nuclear power is the main focus of CO2 control. The Ministry of International Trade and Industry (MITI) announced a long-term energy supply and demand outlook[1] in June 1994 (ACE, 1994). The report, outlining the long-term energy use requirements for Japan, argued that 20 nuclear power plants will be required by 2010 to stabilize CO2 emissions at the required 1990 per capita level. Japanese utilities announced a voluntary action plan on the control of CO2 emissions in November 1996 (JFEO, 1997). The plan outlined the efforts that the utilities would make to reduce CO_2 emissions per unit of electricity by about 20% by 2010 as compared to the 1990 actual emissions throughout the entire electric power industry. Nuclear power is listed at the top of the measures necessary to achieve this goal.

The rationale behind policies that stress nuclear power focuses on the fact that nuclear power is the least-cost technology of power generation for resource-poor Japan and, consequently, of CO2 emissions control. Because of its enormous influence on the entire economy, the cost-effectiveness of CO2 emissions control is the main concern of the government and the utilities. The cost-competitiveness of nuclear power is a predominate factor of technology choice.

The COP3 established a timetable as well as numerical targets for CO2 emissions control. Cost-effectiveness is an essential guideline for technology choice, but not necessarily an optimal guideline because the lead-time for nuclear power plant development is approaching 25 years in

[1] The outlook was prepared by the Advisory Committee for Energy. In response to the agreement of the COP3, the MITI is revising the outlook. Whether the outlook is a projection or a plan is controversy.

Japan due to the difficulty in siting new power stations. This long and volatile lead-time could be a significant risk, obstructing the implementation of CO_2 emissions control.

In addition, since the amendment of the Electricity Utility Industry Law in 1995, independent power producers have entered the Japanese utility market. The goal of the deregulation was to reduce the price of electricity. Low prices, however, can promote high consumption and, consequently, CO_2 emissions. Because the existing utilities have an almost exclusive responsibility to develop nuclear power plants, a nuclear-leaning policy could disturb fair market-competition, leaving the roles and responsibilities of independent power producers vague. To comply with the COP3 agreement, CO_2 emissions control should be consistent with deregulation and vice-versa.

This thesis reconsiders technology choice and policy choice for CO_2 emissions control of Japan's utilities. It asks two key questions: how can risk in the implementation be incorporated into technology choice; and how can two policies—CO_2 emissions control and deregulation—be harmonized?

To answer these questions, chapter two will explore the current CO_2 emissions control policies of Japan's government and utilities. Chapter three investigates technology options for CO_2 emissions control in terms of costs and barriers to implementation. Chapter four demonstrates how the long lead-time in nuclear plant construction entails the risk of delaying CO_2 emissions control. Chapter four also develops technology portfolios to incorporate risks into technology choice, shedding light on the trade-off between cost-effectiveness and risks. Chapter five discusses policy choice for CO_2 emissions control in deregulated markets and analyzes the interaction between CO_2 emissions control and deregulation in terms of technology portfolios and market-competition, recommending a tradable certificate system of carbon-free power generation as a workable policy. Chapter six summarizes the main findings in light of technology and policy choice.

2. CO2 EMISSIONS AND CONTROL POLICY

This chapter presents an overview of CO2 emissions and control policies within Japan's utilities and government. It begins by exploring current CO2 emissions, which is 60% of the United States' emissions per unit of electricity. The already low CO2 emissions in Japan make it difficult to further reduce CO2 emissions both economically and technologically. Secondly, this chapter will provide an overview of the control policies of Japan's energy utilities and government. Before the May 1992 United Nations Conference on Environment and Development, Japan had announced the Action Program to Arrest Global Warming in October 1990. The goal of this program was to stabilize CO2 emission per capita at the 1990 level by 2000. CO2 emissions in 1996 already exceeds this goal. However, the agreement of the COP3 requires Japan to reduce CO2 emissions below the 1990 level by 6%. The government is now rethinking their policy.

2.1 CO2 EMISSIONS

Japan emitted 343 million t-Carbon in 1994. This amount accounts for 4.9% of the total emissions worldwide. The burning of fossil fuels in the energy sector accounted for 91.7% of domestic emissions. The remainder was made up of other industrial sources (cement making, etc.) at 4.5% and the incineration of wastes providing only 3.8% of the total. The utilities account for 29.4% of the domestic emissions (EAJ, 1997a and MFAJ, 1998). Consequently, Japan's utilities account for 1.4% of total emissions worldwide.

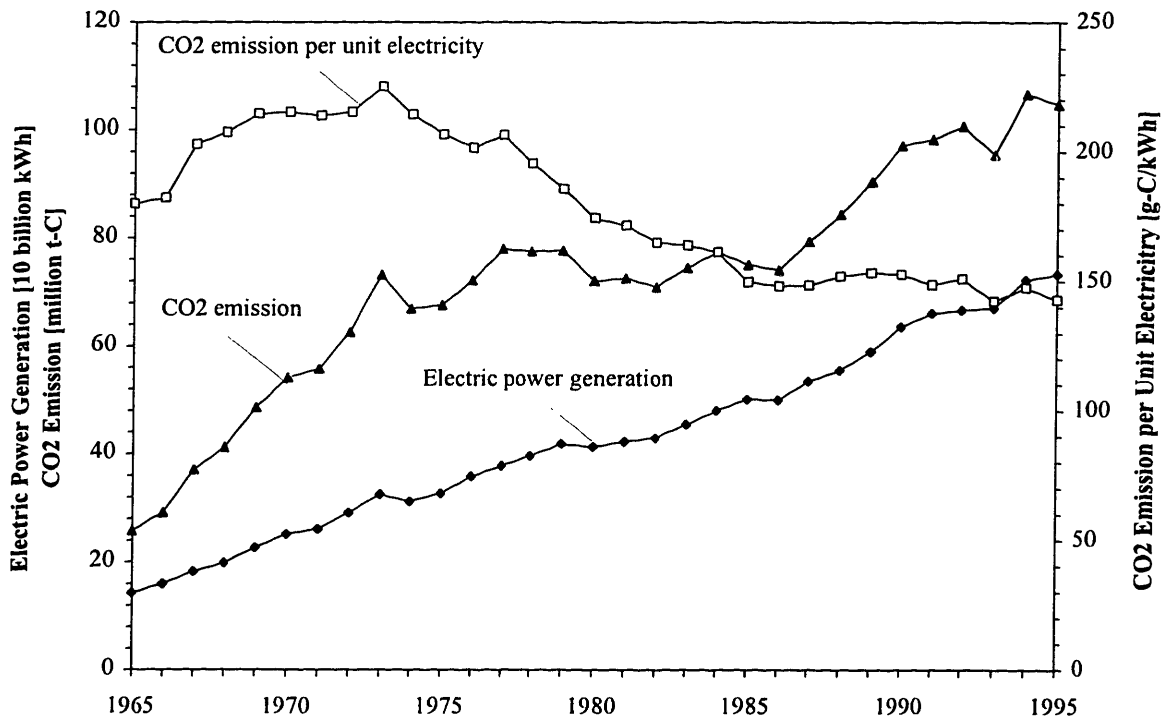
Table 2-1 shows average CO2 emissions per unit of electricity among major countries (FEPC, 1998 and IEA 1997). CO2 emissions per unit of electricity, or "CO2 intensity" of Japan's electrical power generation, is 63% of that of the United States, and 73% of that of the United Kingdom. These low emissions are due in large part to the high thermal-efficiency of Japanese power generation and the large share of nuclear power and natural gas in power sources. Following two recent oil crises, resource-poor Japan has made every effort to improve energy efficiency and diversify identified energy resources. These efforts have made the CO2 intensity of Japanese utilities lower than those of other OECD countries.

Figure 2-1 shows the trend of CO_2 emissions by the Japanese power utilities (EDMC, 1997). In the past 30 years, power generation has increased five-fold, although CO_2 emission has shown only a four-fold increase. CO_2 intensity peaked in 1997 then decreased until 1985. Since then, it has remained generally on the same level. These data suggest that further reduction of CO_2 emissions will not be easy for Japan's utilities, which face a growth in energy demand.

Table 2-1 CO2 Emission per Unit Electricity and Factors Affecting the Emissions

		US	UK	Germany	Canada	France	Italy	Japan
Thermal Power	[kg-C/kWh]	0.229	0.196	0.251	0.227	0.206	0.170	0.159
Total	[kg-C/kWh]	0.161	0.138	0.166	0.046	0.015	0.133	0.101
Coal		57.5%	50.9%	59.0%	25.2%	5.7%	12.0%	17.5%
Oil		2.7%	3.1%	1.6%	2.7%	0.3%	54.3%	24.7%
Natural gas		14.2%	12.6%	7.5%	4.1%	0.5%	18.2%	18.3%
Nuclear		21.1%	32.6%	30.6%	34.0%	87.3%	0.0%	35.6%
Hydroelectric		2.7%	0.6%	1.3%	34.0%	6.1%	8.6%	2.9%
Others		1.8%	0.0%	0.1%	0.0%	0.0%	6.8%	0.9%
Thermal Effeciency		32.7%	35.7%	39.8%	31.7%	34.4%	38.3%	38.9%
Teasmission/Distribution Loss		5.4%	9.4%	4.6%	8.0%	7.2%	6.7%	5.5%

Source:FEPC 1998
IEA 1997



Source: Prepered from EDMC 1997

Figure 2-1 Trend of CO2 emission in Japan's Utilities

2.2 CO2 Control Policy

The government's commitments to CO2 emissions control dates back to the Council of Minister for Global Environment Conservation in May 1989. The Council proposed to the international community in June 1990 "the Global Rejuvenation Program". The idea underlying the program was to rejuvenate the global environment over the next 100 years by launching a comprehensive, long-term international movement to control CO2 emissions. To do so, the program proposed to expand scientific knowledge of global climate change and to develop and introduce new clean technologies.

In October 1990, the Council announced "the Action Program to Arrest Global Warming." The program was a virtual master plan of CO2 emissions control that guided policy until COP3 in December 1997. The historical significance of the "Action Program" was to set up a national target of CO2 emissions control. The target was to stabilize CO2 emissions at the 1990 per capita level from 2000 onward

In July 1992, the United Nations Conference on Environment and Development was held in Rio de Janeiro. Japan, along with 150 other countries, signed the United Nations Framework Convention on Climate Change. The Convention stipulated that developed countries, including Japan, should try to reduce CO2 emissions to 1990 levels by the end of the decade.

In response to the agreement in Rio, the Ministry of International Trade and Industry revised the Long-term Energy Supply and Demand Outlook in June 1994. Table 2-2 summarizes the outlook. While the MITI hedges on whether the Outlook is a plan or a projection, the Outlook asserts that nuclear power will produce 310 billion kWh by the year 2000 and 480 billion kWh by 2010 so that CO2 emissions per capita will be at the 1990 level stabilized from 2000 onward.

Assuming that the capacity for nuclear power plants is 1.35 million kW and the annual utilization rate is 80%, 20 new plants are necessary to meet the outlook. Since 1966, Japan has sited 18 nuclear power stations and operated 53 nuclear power plants. Their total capacity was 42.7 million kW and the total output was 302 billion kWh in 1997. Twenty new plants are equal to 38% of the total capacity of existing plants and 480 billion kWh is 1.6 times larger than the total output of current facilities.

Table 2-2 A Long-term Energy Supply and Demand Outlook

		1992 (actual)		2000		2010	
Final Energy Consumption	[million kℓ*]	360		388		423	
Industrial	[million kℓ*]	181	50.3%	187	48.2%	200	47.3%
Residential and Commercial	[million kℓ*]	93	25.8%	109	28.1%	128	30.3%
Transportation	[million kℓ*]	86	23.9%	92	23.7%	95	22.5%
Primary Supply	[million kℓ*]	541		582		635	
Oil	[million kℓ]	315	58.2%	308	52.9%	303	47.7%
Coal	[million t]	116	16.1%	130	16.4%	134	15.4%
Natural Gas	[million t]	41	10.6%	53	12.9%	58	12.8%
Nuclear	[billion kWh]	223	10.0%	310	12.3%	480	16.9%
Hydroelectric	[billion kWh]	79	3.8%	86	3.4%	105	3.7%
Geothermal	[million kℓ*]	0.6	0.1%	1.0	0.2%	3.8	0.6%
New Energies	[million kℓ*]	6.7	1.2%	12.1	2.0%	19.1	3.0%

*: oil equivalent

Source: ACE 1994

In addition to nuclear power, the Outlook states the expectations for the expansion of "new energies." New energies are defined as energies which do not come into conventional energies listed in Table 2-2. The Outlook expects that new energies will increase by 1.8 times by the year 2000, 2.9 times by the year 2010.

The Outlook itemizes the new forms of energy supply, and defines them as the three "res"; renewable energy such as solar power, waste power generation through recycling of waste materials[2], and renovation of conventional technology such as co-generation. By definition, the new forms of energy supply involve both conventional energies and new energies.

Table 2-3 itemizes the new forms of energy supply. As shown in Table 2-2, the Outlook expects that new energies will increase by 1.8 times by the year 2000, and 2.9 times by the year 2010. However, for power generation the increase of new energies is more drastic. For instance, the Outlook expects that solar power will increase by 10 times by the year 2000 and more than one thousand times by the year 2010. Similarly, the Outlook expects that wind power will increase by 10 times and 20 times, while waste power generation is expected to increase by 4.5 times and 9 times in the same periods. Nevertheless, the share in the total electricity production is around 1%.

[2] This wording contradicts itself. Waste power generation recovers the waste heat of the incineration of waste materials.

Table 2-3 New Forms of Energy Supply

	actual 1992 [thousand kℓ]*	2000 [thousand kℓ]*	2010 [thousand kℓ]*
Renewable			
Solar Power	0.4	40	450
Wind Power	1	10	20
Solar Thermal	1,130	3,000	5,500
Thermal Energy Conversion	6	200	580
Recycle			
Waste Power Generation	232	1,060	2,120
Waste Heat Recovery	39	70	140
Others	4,880	5,050	5,390
Renovation			
Co-generation	2,770	5,230	8,790
Fuel cell	2	105	1,230
Methanol, Coal Liquefaction	0	0	960
Alternative Transportation Fuel	3	680	3,240
Total **	9,063	15,340	27,230

*: oil equivalent Source; ACE 1994

**: Fuel cell counts as fuel cell and cogeneration twice.

New forms of energy supply involves conventional energies and new energies.

In September 1994, based on the Outlook, the government reported to the Secretariat of the Framework Convention on Climate Change convention that CO2 emissions in 2000 will be about 330 million t-C (up 10 million t-C or about 3% from 1990) and that per-capita emissions will be about 2.6 t-C per capita (more or less level with those of 1990). The actual CO2 emissions in 1995, however, already exceeded the prospect of the year 2000 by 2%, which was 8% over 1990 rates. Figure 2-1 shows the actual records and the prospects of the outlook in terms of primary energy supply and CO2 emissions. Up until 1993, energy supply and demand had stayed at almost identical levels to the Outlook because of economic stagnation. However, by 1994 primary energy supply jumped up by 5.4 % per year, leading to CO2 emissions that exceeded the projection for the year 2000, ballooning by 6.1%.

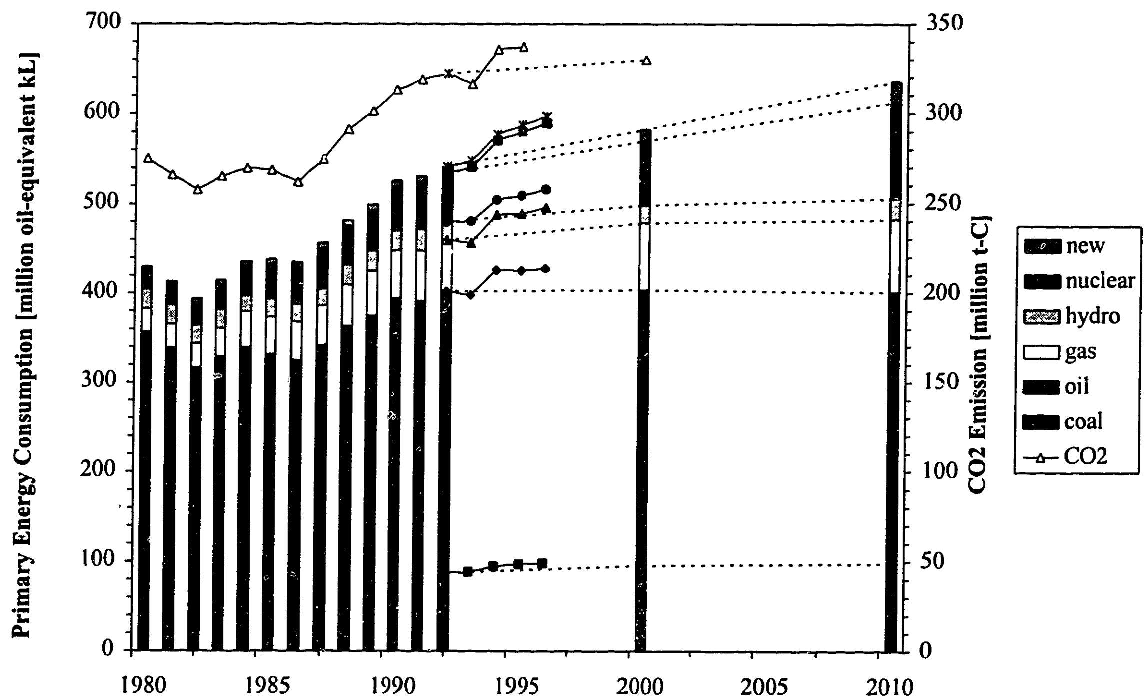
For power generation, the utilities have commissioned 12 nuclear power plants since 1991. As of 1998, the total capacity of nuclear power is 45.24 million kW, already reaching the prospect of the year 2000. The output of nuclear power was 302 billion kWh in 1996[3]. Because two plants were commissioned in mid-1997, nuclear power produces 310 billion kWh when all plants run at

[3] The data for 1997 is not available.

the utilization rate of 78%. Since the utilization rate was 80.2% on average in 1996 (JEA, 1996), the output of nuclear power in 1997 reached the projection of the Outlook in the year 2000.

The reason why nuclear power will meet the Outlook's specifications is that all newly commissioned plants were already under construction when the Outlook was prepared. Once actual construction is begun, it is usually completed on schedule. The most difficult part of nuclear power plant development is the pre-construction periods necessary to secure the consent for plant development. Therefore, there is no guarantee that the projections of the year 2010 will be met.

In comparison, while nuclear power generation increased 30% from 1992 to 1995, ahead of schedule, new energy increased 1% in the same time period. The Advisory Committee for Energy (ACE), which prepared the Outlook, analyzed the aftermath of the Outlook and concluded that high costs impeded the diffusion of new energies (ACE, 1996).



Source: ACE 1994, ANRE 1996, EDMC 1997

Figure 2-2 "Long-term Energy Supply and Demand Outlook" and Actual Recedes

New-energy policy has put the most weight on the development of and subsidies for new-energy related technology. For instance, after the announcement the Global Rejuvenation Program, the MITI revised "the *Sunshine Project* Program" for the first time in 16 years. The original program had begun after the first oil crisis in order to develop energy technology. In 1993, the MITI revised other national projects concerned with energy technology and started "*the New Sunshine Project.*" The project promotes six main technologies; fuel cell, renewable energies, coal liquefaction, super-conductivity, and hydrogen, and CO2 fixation.

In December 1994, the government adopted the Basic Guidelines for New Energy Introduction, the first basic guidelines ever drawn up by the government, to accelerate the introduction of new energies. The Guidelines set up the targets for the introduction of new energies

Japan's Utilities

The Federation of Electric Power Companies (FEPC) announced the Keidanren Voluntary Action Plan on the Environment in November 1996. The action plan stated that:

> Efforts will be made to reduce in 2010 the CO2 emission per unit of output in the electric power industry as a whole by about 20% as compared to the 1990 actual. As a result, although the electric power output in 2010 is expected to increased 1.5 times over 1990, the amount of CO2 emission will be kept down to an increase of about 1.2 times (JFEO, 1997).

To achieve this goal, the FEPC proposed five measures: promoting nuclear power generation; improving efficiency of energy use; adopting new energy; developing the technologies of CO2 recovery and disposal; and supporting energy-saving.

3. TECHNOLOGY OPTIONS

This chapter surveys the technology options for CO2 control. It begins by discussing the necessity of improving CO2 intensity, considering the political environment surrounding the utilities. Then, it surveys a technological scheme for improving CO2 intensity that involves the improvement of thermal efficiency, fuel switching, as well as others. The following two sections investigate the costs and barriers of nuclear power plant development. They analyze why nuclear power has cost-competitiveness in Japan and what difficulty nuclear power has despite its cost-competitiveness. The last part creates a cost/risk matrix of technology options

3.1 IMPROVING CO2 INTENSITY

There are number of technology options available to reduce CO2 emissions by Japanese utilities. Among them are demand side management (DSM), the improvement of CO2 intensity, and the offset of CO2 emission. From the technological point of view, finding the least costly options would reduce CO2 emissions most economically. However, the reality of the political environment requires the utilities to reduce CO2 emissions from their power plants rather than reducing them elsewhere. This section discusses the necessity of reducing CO2 emissions from power plants within the context of the political environment surrounding the utilities.

The net CO2 emissions from the utilities can be described by the difference between CO2 emissions from power plants and the offset to them somewhere outside power plants.

$$E = Q \cdot \eta - O$$

where

E = the net CO2 emission [t-C]

Q = the electricity production [kWh]

η = the CO2 emission per unit electricity or CO2 intensity of electricity [t-C/kWh]

O = the offset of CO2 emission [t-C]

There are three options to reduce the net CO2 emissions from utilities. First, demand side management improves the efficiency of end use and reduces the demand of electricity, Q. Second, the improvement of CO2 intensity, h, enhances the efficiency of power generation or switches fuels from high-carbon fuels to such low-carbon fuels as nuclear power and natural gas. Third, the offset is the reduction of CO2 emissions from somewhere outside power stations. Joint implementations and emissions permits trade offset the CO2 emissions from power plants.

From the consumers' point of view, the reduction of electricity consumption is the outcome of consumers' effort. Similarly emission trade and joint implementations are the outcome of other sectors or other countries. Therefore, unless the utilities reduce their own emissions, the public will look askance at the utilities: the utilities are seen to be shifting responsibility to others, enjoying the fruits of their achievement.

Economically, the utilities share the cost of demand side management and the emissions offset with their consumers. Nevertheless, the public stil! considers the utilities not a "free-rider" but not a "driver" of CO2 control: the utilities are just a "paid-rider." This makes no economic sense, but the real problem is that the utilities lose the public trust. The public mistrust makes it more difficult to resolve already existing barriers to siting power stations, particularly nuclear power stations and radioactive-waste disposal repositories.

For these reasons, the following section focuses on the CO2 emissions control from power generation. As discussed in Chapter 2, the CO2 intensity of Japan's utilities is 60% of that of the U.S. The already low intensity raises the magical cost of improving it. From the technological point of view, demand side management and the emission offset can reduce CO2 emissions more cost-effectively than the improvement of CO2 intensity. Nevertheless, the problem facing Japan's utilities is that the public may still ask the utilities to reduce their own emissions. For these reasons, although demand side management and emission offset are important options for CO2 control, they are outside the scope of this thesis

3.2 TECHNOLOGICAL SCHEME FOR CO2 CONTROL

As the concern over climate change increases, extensive numbers of technologies have been studied and proposed to deal with this situation (Watson, et al ed., 1996). For power generation, a collaborative effort between the United States Department of Energy and the electric utility industry identified and proposed a number of technology options for greenhouse gas reduction (DOE, 1994). Although there are a number of technology options, the point of them is to improve

CO_2 intensity of electricity. There are three dependencies in improving CO_2 intensity: fuel choice, the thermal efficiency of power generation, and power plant utilization rates.

Fuel Choice and Thermal Efficiency

Fuel choice and thermal efficiency are directly related to CO_2:

$$\eta = a \cdot \frac{C}{\lambda}$$

where

η = the CO_2 intensity of electricity [g-C/kWh]

C = the carbon content of fuel [g-C/MJ-fuel]

λ = the thermal efficiency of power generation [MJ-electric power/MJ-fuel]

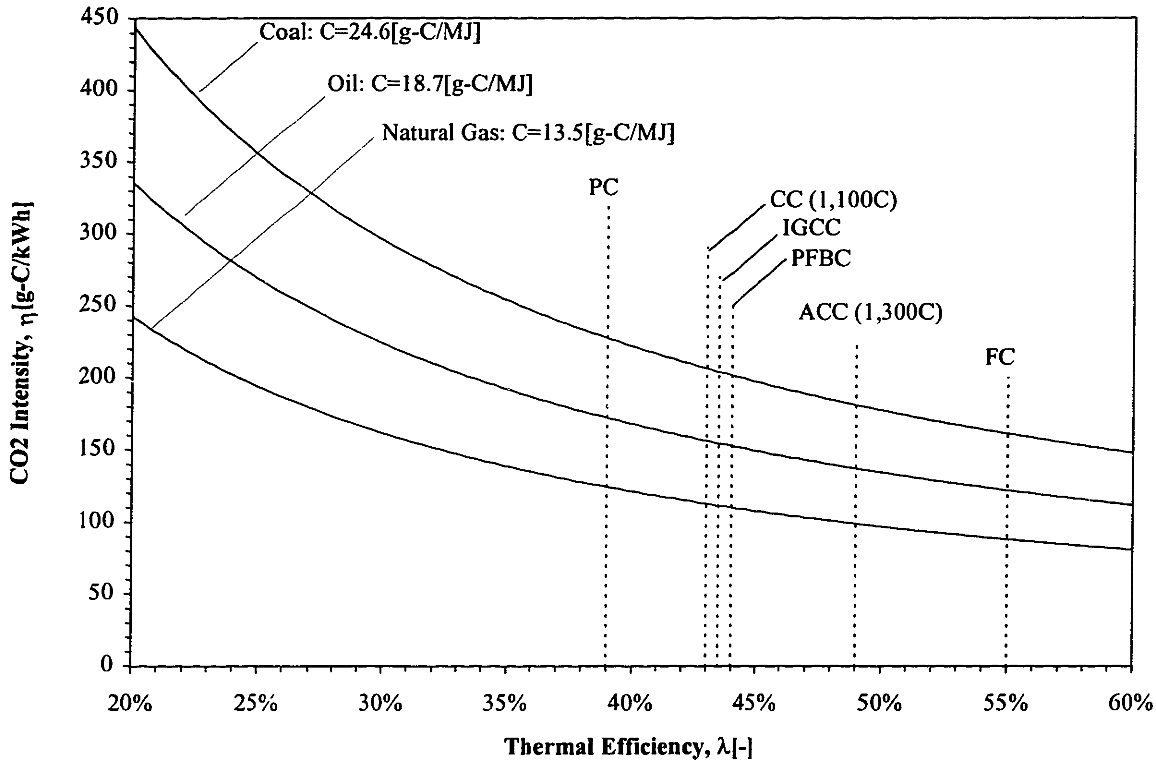
a = a constant, 3.60 [MJ/kWh]

Fuel choice is the most influential factor for the improvement of CO_2 intensity. Included in ' carbon-free" power generation are nuclear power, hydroelectric power, solar power, wind power. In addition to these, there is "carbon-neutral" power generation. For instance, biomass burning power generation adds no CO_2 into the atmosphere as long as the same amount of biomass is regenerated through afforestation, artificial cultivation, or natural growing. Municipal solid waste mass is a mixture of biomass and fossil resources. Paper is an example of the former and plastics of the latter. Therefore, it can add CO_2 into the atmosphere. Japan burns 72% of the its total municipal sold waste due to the lack of landfill space (IEA, 1995). There are some 1,900 incineration plants; 6.8% of them produce electricity (ANRE, 1997). Because municipal solid waste disposal emits CO_2 in either case, power generation in refuse incinerators increases no gross CO_2 emissions. For this reason, municipal solid waste mass is reasonably eligible for carbon-neutral fuel in Japan.

Improving thermal efficiency reduces fuel consumption and, consequently, CO_2 emission. Japan has no significant natural resources of its own and the utilities have made efforts to ensure the efficient utilization of energy sources. The government has tacitly approved of the utilities' use of their monopolistic profits for energy research. As a result, the efficiency of power generation is among the best in OEDC countries, as shown in Chapter 2.

Figure 3-1 shows the relationship between CO2 intensity and thermal efficiencies by fuel sort. CO2 intensities of carbon-free fuels and carbon-neutral fuels are always zero regardless of thermal efficiency. CO2 intensity decreases with the increase of thermal efficiencies. Efficiency gains of 50 ~ 60% could technologically be feasible. However, actual thermal efficiencies depend on load factors. On one hand, power plants generate electricity most efficiently at the design load where the efficiency is equal to the design value. On the other hand, the efficiency decreases below the design value at the partial load. Table 3-1 shows the actual records of average thermal efficiencies and average load factors. Due to the daily and seasonal fluctuation of demand, the load factor of Japan's utilities is 55.3%. The low load factor reduces actual efficiencies below the design level.

For instance, the weighted average of thermal efficiencies at the Tokyo Electric Power Company was 40.22%, while the actual efficiency was 39.04% in 1995. The gap of 1.18 percentage points is equivalent to 3% of the total output of the Company's thermal power plants. Consequently, if the Company could operate its thermal power plants at design efficiency, 3% of fossil fuels would be conserved, and there would be a 3% reduction of CO2 emissions. In this sense, demand side management can contribute to CO2 control, leveling the demand and increasing the actual thermal efficiency



PC: Pulverized Coal-burning Power Plants
CC: Combined Cycle (1,100C°)
IGCC: Integrated Coal Gasification Combined Cycle
PFBC:Pressurized Fluid-bed Boiler Combined Cycle
ACC: Advanced Combined Cycle (1,300 C°)
FC: Fuel Cell

Figure 3-1 CO2 Intensity

Table 3-1 Efficiency and Load Factor

	thermal efficiency	transmission/ distribution loss	load factor
US	32.7%	5.4%	61.2%
UK	35.7%	9.4%	67.3%
Germany	39.8%	4.6%	69.3%
Canada	31.7%	8.0%	65.1%
France	34.4%	7.2%	66.2%
Itary	38.3%	6.7%	50.3%
Japan	38.9%	5.5%	55.0%

as of 1994

Source: JEA 1997

Utilization Rate

CO2 emission is obtained by multiplying CO2 intensity and electricity production. Electricity production, in turn, depends on the capacity and utilization rate of individual power plants. The utilization rate is defined as the ratio of actual annual output to maximum annual output:

$$\text{utilization rate}[-] \equiv \frac{\text{actual annual output [kWh/year]}}{\text{capacity[kW]} \times 365[\text{day/year}] \times 24[\text{hr/day}]}$$

In Japan, utilization rates are 80.2 % for nuclear power, 71.6% for coal, 30.1% for oil, 54.7% for natural gas, and 38.7% for hydroelectric power (ANRE, 1996b and JEA, 1996, 1997). Due to their low running-costs, the utilization rates for nuclear power and coal are greater than those for oil and natural gas. In particular, nuclear power plants run continuously except during routine maintenance periods. Though law regulates the interval between routine maintenance, lengthening the interval raises the utilization rate of nuclear power plants and reduces those of burning fossil fuel.

Similarly, the relatively low utilization rate of natural gas results mainly from the capability to follow a fluctuating demand. Natural gas burning power plants such as gas turbines run during the daytime to satisfy peak demand and then reduce output at night. For this reason, leveling the demand raises the utilization rate of natural gas burning power plants and reduces those of coal or oil burning ones. In this case, raising the utilization rates of low-carbon fuel power plants reduce CO2 emissions.

Plant Capacity

CO2 emissions depend on three factors: fuel choice, thermal efficiency, and utilization rates. Form the viewpoint of power plant development three factors affect a plant's capacity for CO2 control. That is, the plant capacities necessary for CO2 control differ from fuel to fuel because of the differences of three factors. For instance, the utilization rate of nuclear power is 80.2% while that of solar power is less than 15% because solar power does not work at night (ERSJ, 1997). Therefore, plant capacity equivalent to nuclear power is more than 5 times greater than that of nuclear power.

Figure 3-2 shows plant capacities equivalent to nuclear power in terms of CO_2 control. A nuclear power plant of 1,350 MW produces electricity of 9460 GWh, running at the utilization of

80%. When a new energy power plant is substituted for the nuclear power plant, the capacity is 9,000 MW for the utilization rate of 15% and 3,600 MW for that of 30%. Because of the low utilization rate, the capacity of a new energy power plant is greater than that of a nuclear power plant.

Similarly, when a LNG-burning thermal power plant is substituted for the nuclear power plant, the capacity is 1,964 MW because the utilization of the LNG plant is 0.55. At the same time, the LNG plant emits CO2 of 918 kt-C. In order to offset the emissions, the utilities have to retrofit existing thermal power plants or switch fuels. For instance, when utilities improve the efficiency of coal burning thermal power plants from 38% to 43%, the capacity increases to 8,758 MW. In such a case, the total capacity of the LNG plant and the coal plants is 10,722 MW. Similarly, when the utilities switch the fuels of existing plants from coal to LNG, the total capacity is 3,554 MW.

All existing power plants are replaced at the end of their life. In such a case, the cost of the replacements is not that of CO2 abatement. However, when utilities replace plants before the end of their natural life span in order to control CO2, the utilities can not recover a portion of the original cost. The stranded cost is included in the cost of CO2 control. On the contrary, when the utilities change the fuels being used in the plants to be built in the future, no stranded costs arise.

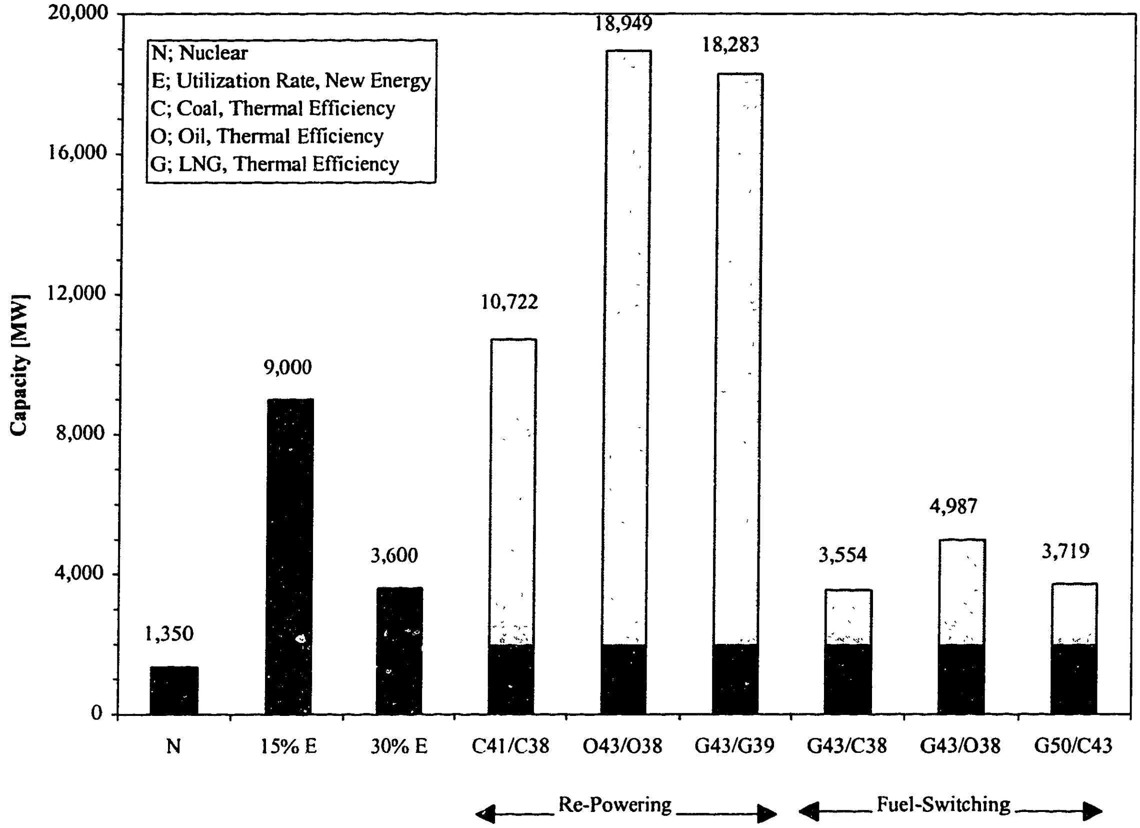


Figure 3-2 Equivalent Capacity to CO2 Control

3.3 COST OF NUCLEAR POWER GENERATION

When CO2 emissions are stabilized at the 1990 level, the economic influence would reach from 0.5% to 2% of GDP in OECD countries[4] (Bruce et al, 1996). MITI asserts that CO2 control affects Japan more seriously than other OECD countries (MITI, 1997). For this reason, cost-competitiveness is the main concern of both the government and the utilities. Nuclear power is the least-cost technology of power generation in resource-poor Japan. However, not only the price of fossil fuels but also other factors contribute to the cost-competitiveness of nuclear power.

<u>Cost of Power Generation</u>

For Japanese power generation, nuclear power is a less-costly technology. Table 3-2 summarizes the costs of power generation in both Japan and the U.S. (ANRE, 1994 and Flavin, 1994). The cost of Japanese power generation is higher than in the U.S., but Japan's nuclear power

[4] The economic loss of traffic accidents is estimated at 0.9% of GND in Japan.

is considerably cheaper than in the U.S. Two facts can explain why nuclear power has cost-competitiveness in Japan: the high costs of thermal power and the implicit preferential treatment towards nuclear power.

Many things contribute to rise in the cost of thermal power generation, but the main reasons are three-fold: First, Japan imports most fossil fuels, particularly natural gas imported as liquefied natural gas. Second, sulfur premiums and pollution control regulations push up the cost of coal and oil, requiring flue gas treatments, such as desulfuzation, denitration, and dust collection. Third, energy taxes also raise the cost of fossil fuels. By contrast, the large part of the tax revenue is spent on nuclear power plant development, creating an implicit subsidy for nuclear power.

Table 3-2 Costs of Power Generation in Japan and the US

	Japan		US
	[yen/kWh]	[cent/kWh]	[cent/kWh]
Coal	10	8.3	5 ~ 6
LNG	9	7.5	4 ~ 5
Nuclear	9	7.5	10 ~ 21
Wind	32	26.7	5 ~7

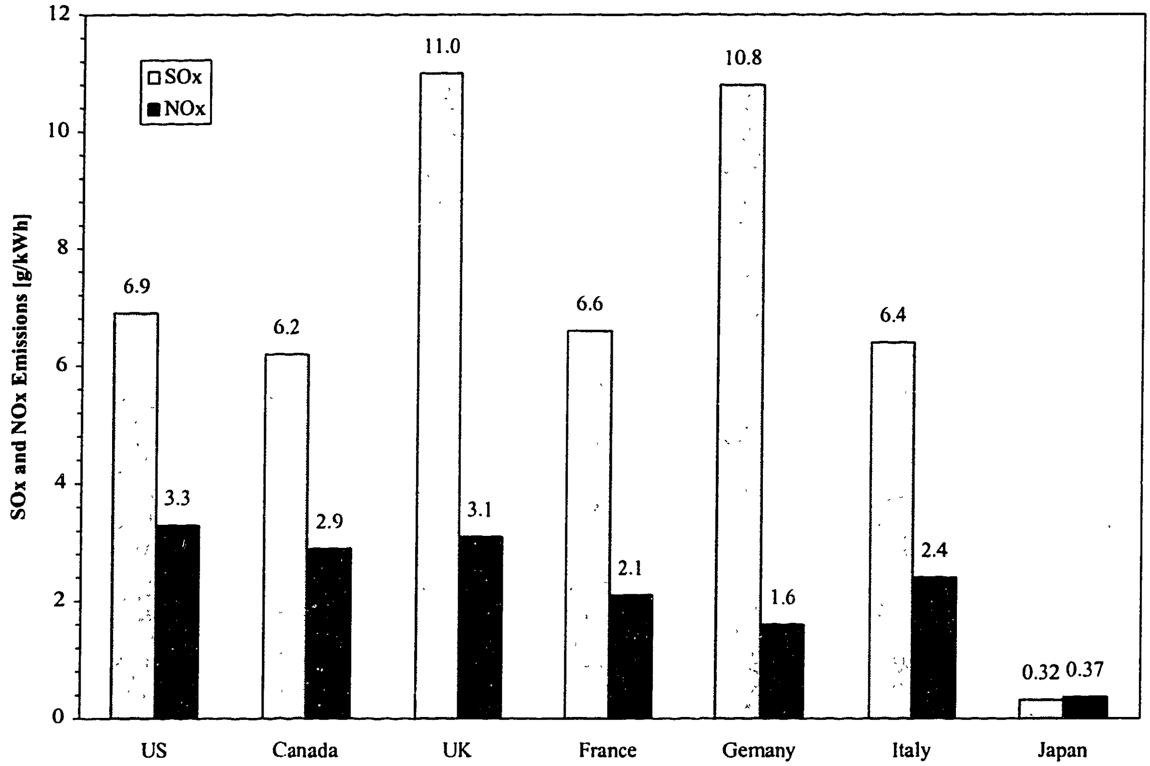
exchage rate; 120[yen/dollar]

Source: ANRE 1994
Flavin 1994

Costs of Air Pollution Control

In the past twenty years, Japan has doubled its GDP and increased the consumption of fossil fuels by 41%. Nevertheless, sulfur oxide emissions decreased by 82% and nitrogen oxides emissions decreased by 21% in the same period (OECD, 1994). Many industries contributed to the success of pollution control including the utilities. Figure 3-1 shows the comparison of sulfur oxides and nitrogen oxides emissions per unit electricity generated by thermal power plants (FEPC, 1995). Japan's utilities are the most successful in air pollution control among OECD countries.

Air pollution control raises the costs of thermal power generation. Table 3-3 shows the costs of pollution control (Hasegawa, 1995). The costs of pollution control equipment account for 4.8 ~ 12.4% of the total cost of oil-burning power generation, and 18.2 % of that of coal burning power generation. The costs of air pollution increase the cost of thermal power generation and enhance the cost-competitiveness of nuclear power generation.



Source: FEPC 1995

Figure 3-3 SOx and NOx Emissions of Thermal Power Plants

Table 3-3 Thermal Power Generation and Pollution Abatement Cost

(Unit: yen/kWh, 1987)

Fuel	Heavy fuel oil	Hevry fuel oil	Coal
Sulfer content [%}	0.2	3.0	1.2
Power generation			
Fuel cost	5.6	5.0	3.1
Fixed, operating costs	6.3	·6.3	7.7
Sub-total	11.9	11.3	10.8
Pollution abatement			
Electrostatic precipitaion	0.1	0.1	0.2
Desulfurization		1.0	1.2
Denitration	0.2	0.2	0.4
Others	0.3	0.3	0.7
Sub-total	0.6 (4.8%)	1.6 (12.4%)	2.4 (18.2%)
Total	12.5	12.9	13.2

Source: Hasegawa 1995

Tax on Fossil Fuels and Power Generation

Japan levies taxes on fossil fuel consumption and power generation (Figure 3-4). National taxes involve a tariff, an oil tax, and a tax on power generation. The tariff is 315 yen per kℓ, but will be abolished by 2002. An oil tax was enacted in 1978 to supplement the fiscal resources of oil store. The rate was 2,040 yen per kℓ for oil, and 720 yen per t for natural gas. The tariff and the tax account for around 15% of the cost of oil and 3% of that of liquefied natural gas[5].

A tax on power generation was enacted in 1974 after the first oil crisis in order to promote power development. After the second oil crisis, tax revenue also has been spent on the diversification of power sources. The tax rate is 445 yen per thousand kWh and accounts for 2.3% of the price of electricity. The revenue is spent on power development at 160 yen, and on the diversification at 285 yen of 445 yen. Although nuclear power is subject to the tax as well, a large part of the tax revenue is spent in siting new nuclear power plants. For instance, while the subsidy is usually spent on the regions where power plants are located, the government can subsidize a region where the utilities carry out environmental assessment for nuclear power plant development even before the development is officially approved by the government (JEA, 1996). The tax is an implicit subsidy for nuclear power.

The existing tax on fossil fuel can be translated CO2-emission equivalent rate. Therefore, the tax can be considered an implicit carbon tax. Table 3-4 shows an implicit carbon tax (Hoeller, 1991). The implicit carbon tax in Japan is 2.8 times higher that in the U.S. The tax revenue from fossil fuel was 3.7 trillion yen in 1993 accounting for 5.7% of the total national tax revenue and 20.8% of the total revenue from indirect taxes (Ishi, 1995). Assuming the price elasticity of fossil fuel is equal to 0.2, an implicit carbon tax is estimated to already mitigate CO2 emissions by 19.3 million t-C, or 5% of the total CO2 emissions from Japan (ERI, 1997).

In addition, air and water pollution from radioactive materials is not subject to the Basic Environment Law. The Law on Compensation for Nuclear Damage confines the accident compensation of utilities within 30 billion yen (250 million dollars). The law prescribes that the national government compensate for damage in excess of 30 billion yen. These preferential treatments also contribute to the cost-competitiveness of nuclear power.

[5] It is assumed that the price of oil and liquefied natural gas are 18.3 [$/barrel], 180 [$/t] respectively and that the exchange rate is 120 [yen/$].

Table 3-4 Implicit Carbon Tax (Unit; US dollars)

implicit carbon tax	US	Japan	Germany	France	Italy	UK	Canada
oil	65	130	212	351	317	297	108
natural gas	0	2	23	38	80	0	0
coal	0	0	0	0	0	0	0
total	28	79	95	229	223	106	52
exchange rate	1.0	128	1.8	6.0	1,302	0.6	1.2

Source: Hoeller 1991

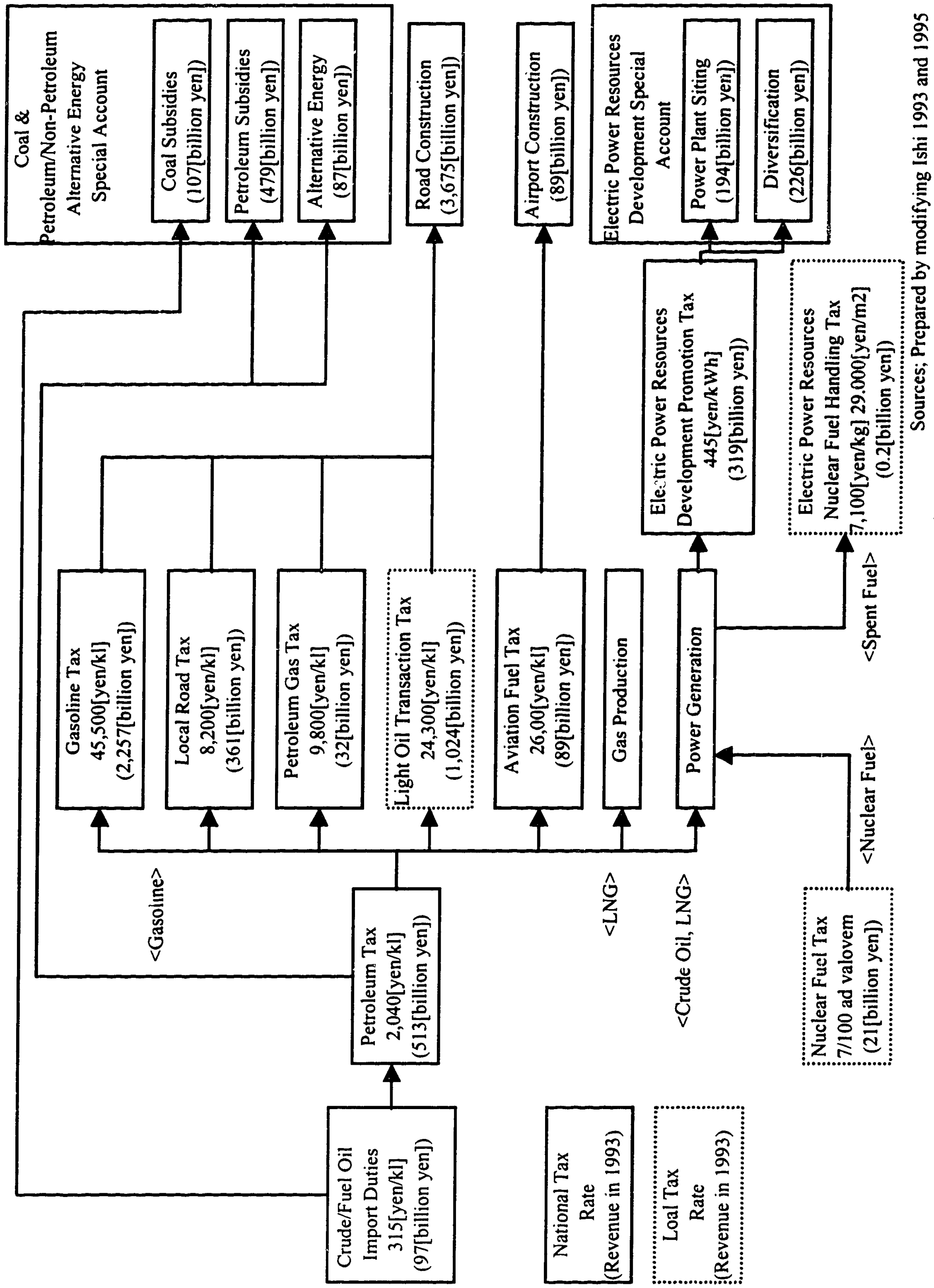


Figure 3-4 Energy Taxes of Japan

3.4 BARRIERS TO NUCLEAR POWER DEVELOPMENT

For CO2 control technologies, cost-effectiveness is an essential guideline for technology choice. However, technological costing, which develops estimations focusing on direct expenditures to implement control technologies, frequently gives much too optimistic results, ignoring social and political barriers. For practical technology choice, the viability of control technologies should be considered. This section explores barriers to nuclear power development.

<u>Timetable of CO2 Control</u>

The COP3 set up a timetable as well as national targets for CO2 emissions control. CO2 emissions controls have to be implemented within an established timetable. Article 3 of the Kyoto protocol to the United Nations Framework Convention on Climate Change (FCCC) states:

> The Parties included in Annex I shall, individually or jointly, ensure that their aggregate anthropogenic carbon dioxide equivalent emissions of the greenhouse gases listed in Annex A do not exceed their assigned amounts, ... in the commitment period 2008 to 2012 (FCCC, 1998).

Japan and other economically advanced countries set up targets timetable at the United Nations Framework Convention on Climate Change held in Rio in 1992. This convention stipulated that economically advanced countries try to reduce CO2 emissions to the level of 1990 by the end of 1990s. The targets and timetable, however, are not legally binding to the signatories.

By contrast, the agreement of the COP3 is legally binding to the signatories. Penalties of non-compliance will be made soon. In addition, the COP3 established more difficult targets than the FCCC. For Japan, the former is to reduce greenhouse emissions to 6% below 1990 levels, while the latter is to stabilize CO2 emissions per capita at 1990 level. MITI maintains that CO2 emissions can not be reduced below 1990 levels and that the reduction of 6% should be achieved through emissions permits trade, a clean development mechanism, and forestation (Fujime, 1998).

<u>Nuclear Power</u>

Although nuclear power usage has increased steadily, the Advisory Committee for Energy, which prepared the outlook as an advisory committee for the minister of MITI, expressed concern over the difficulty of further nuclear power plant development (ACE, 1996). The most difficult part of nuclear power plant development is to identify the site and to secure the consent of the local residents and the local government. A series of scandalous incidents at "Monju" in December 1995 and a "reprocessing facility" in March 1997, run by the Power Reactor and Nuclear Fuel Development Corporation, augmented abiding distrust of nuclear power among a large public.

In August 1996, residents voted directly on whether or not they should sell town land to a utility for the purpose of building a nuclear power station. This was the first inhabitants' poll for a nuclear power station in Japan. The construction of the station was rejected by a vote of 61% to 39%. Although the voting had no legal force in prohibiting the construction of the power station, the utility altered the plant building schedule which had been delayed 17 times for the past 18 years (Nigata Nippo 1996).

Although the utilities make every effort to develop nuclear power plants, the difficulty in siting new plants makes the lead-time long and volatile. As discussed in the next chapter, the lead-time is reaching 25 years in Japan. There are a number of reasons for this difficulty in siting nuclear power plants. Among them, two facts can be pointed out. First, most nuclear power plants are located outside the service area of the utility and supply no electricity to the areas where the plants are located. For instance, while Japan consists of 47 prefectures or administrative divisions, they sometimes are called "electricity- export prefectures," and "electricity-import prefectures." In Tokyo, where more than 30% of the total electricity of Japan is consumed, 94% of total consumption is "imported" from other prefectures. Because nuclear power plants often supply no electricity to the regions where they are located, they are frequently for the residents nothing but unwanted facilities. The typical argument against nuclear power plants is that they should be sited in the areas that need them.

Second, Japan has not yet decided on a policy for radioactive waste disposal. Indeed, Japan has not yet decided who is responsible for radioactive waste disposal: the utilities or the national government. Residents are afraid that not only nuclear power plants but also permanent or interim repositories for nuclear waste will be sited in their regions.

These two barriers are difficult to resolve. The concern over the safety of nuclear power plants can be mediated by the utilities accumulating a strong safety record and establishing trust with the residents. However, from the standpoint of the residents, to prove safety has little to do with the necessity for nuclear power plants. Similarly, the importance of energy security is not a persuasive reason why nuclear power plants should be sited outside of the consuming areas of the generated electricity. Although the government and utilities procrastinate on nuclear waste disposal, it will become a concrete problem sooner or later. In this sense, the concern of the residents is quite reasonable.

In short, because the barriers are not technological or economic, the problem of nuclear plant development is extremely difficult to resolve. Therefore, despite the increasing necessity for nuclear power plants in terms of energy supply and CO2 emissions control, nuclear power plant development has a tendency to be problematic.

3.5 MAPPING CONTROL TECHNOLOGIES

Low-cost and high-uncertainty options have cost-competitiveness but, on the other hand, difficulty in the implementation within a specific time period. Nuclear power is involved in this equation. Liquefied natural gas may come into this equation because Japan is required to import most natural gas and which in turn requires the development of overseas gas fields, transportation system infrastructures, and long-term contracts with exporting countries. In addition, some experts are concerned that the rapid expansion of China's and India's consumption may cause a shortage of LNG supply in the Asian region (Morita, 1998). As discussed in the following section, the cost of natural-gas burning power generation is cheaper than that of oil and coal in Japan while natural gas is the most expensive fuel in the U.S. Therefore, switching fuel from oil and coal to natural gas would reduce CO2 emissions, bringing a net benefit. In other words, the utilities could reduce CO2 emissions free of cost. That, however, produces the same paradox as nuclear power. If natural gas usage was without difficulty, the utilities should have expanded its use already. It is reasonable that natural gas has some difficulties in expansion and, consequently, comes into the segment of low-cost and some uncertainty.

The ideal option is low-cost and low-uncertainty technologies. Conventional energy conversation technologies can be involved in this segment. However, the paradox is similar to that of nuclear power. If technologies had cost-competitiveness and no difficulty in the diffusion, they should have diffused throughout markets already. For instance, there is a long-standing controversy over fluorescent lights (Wallich, 1994). Although fluorescent lighting is more energy-efficient than conventional light bulbs, they have not diffused rapidly into markets due to the higher initial cost. While there are some explanations for consumer behavior (Sanstad, 1995), it is safe to say that technologies, which have not already diffused into the market, have some difficulties preventing this diffusion.

Technologies, which have not yet been feasible practically or economically, are high-cost and high-uncertainty options. Next generation, innovative technologies fall in this segment. Table 3-5 and Table 3-6 lists renewable energy technologies (Dornbusch, 1991) and the cots of them (TEPCO 1997, ANRE, 1997, IERJ 1997 and Flavin, 1994). Future supplies are involved in these segments.

The bottom line of technology mapping is that, from the economic point of view, any technologies, which have not already diffused into the marketplace, have some difficulties in diffusion and implementation. The difficulties are not always the cost of technology but may include other sorts of barriers such as public acceptance of nuclear power, liquefied natural gas infrastructures, and consumer preferences in energy-conservation investments.

When there is a tradeoff between cost-effectiveness and risk in uncertainty, choosing the appropriate combination of control technologies could adjust the balance between cost-effectiveness and risk. In other words, uncertainty over implementation is an important constraint on technology choice. When the timetable is given high priority, high-cost and low-uncertainty technologies could be feasible. From this point of view, Chapter 4 rethinks Japan's utilities' technology choice for CO2 emissions control.

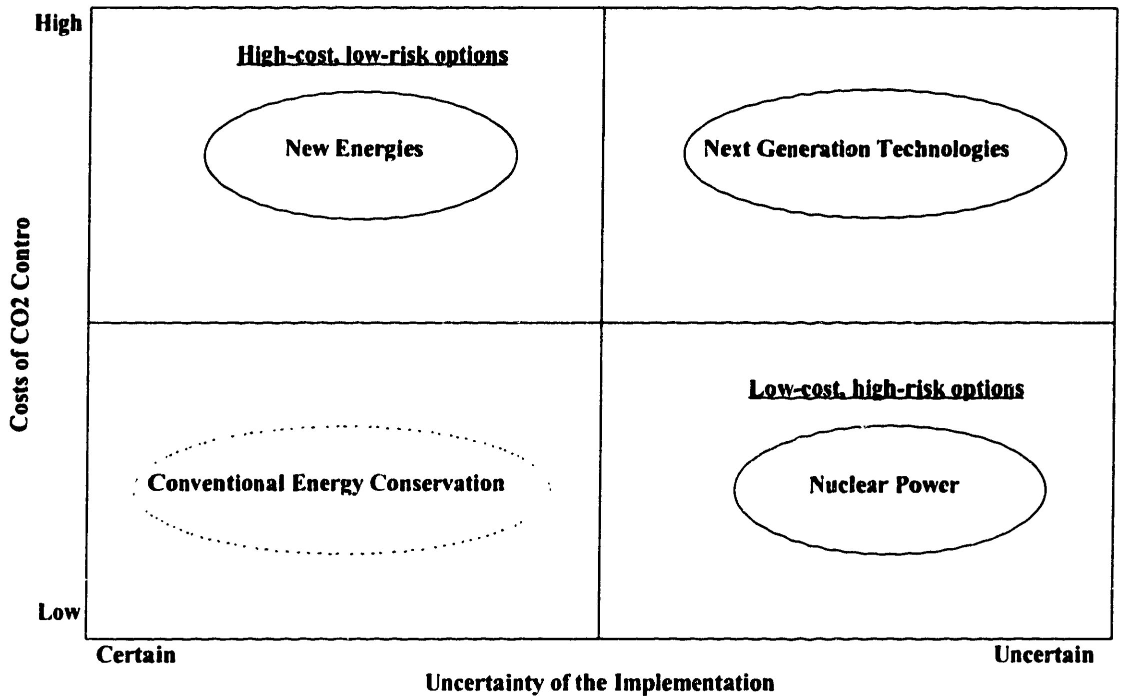


Figure 3-5 Conceptual Mapping CO2 Control Technologies

Table 3-5 Renewable Energy Potential

Proven capability[a]	Transition phase[b]	Future supplies[c]
Hydo power	Wind	Advanced wind
Geothermal	Solar thermal	Advanced solar thermal
Hydrothermal	Ethanol (corn)	Transportation fuel from energy crops
High-temperature electric	Active solar in buildings	Ocean thermal
Low-temperature heat	Geothermal	Advanced geothermal
Biomass	Hydrothermal	Hot dry rock
Direct combustion	Moderate-temperature electric	Geopressure
Gasification	Remote photo voltaic	Magma
Passive solar in buildings		Grid-connected photo voltaic
Small, remote photo voltaic		Wave
		Tidal

a: Mature technologies.
b: Has or is entering market as technology develops, often preferential tax or rate considerations.
c: Advanced technoogis that show potential.
source: Dornbush 1991

Table 3-6 Costs of New Energy Power Generation

	Japan		US	
	[yen/kWh]	[cent/kWh]*	[yen/kWh]*	[cent/kWh]
Solar Power	70 ~ 120	84 ~ 144	48 ~ 84	57 ~ 101
Solar Thermal	n.a.		7 ~ 23	8 ~ 27
Wind Power	24 ~ 46	29 ~ 55	4 ~ 8	5 ~ 9
Geothermal	13 ~ 16	16 ~ 19	3 ~ 9	4 ~ 11
Wave	31 ~ 43	26 ~ 52	7 ~ 8	8 ~ 9
Municipal Solid Waste	7 ~ 13	8 ~ 16	n.a.	
Biomass	n.a.		n.a.	

* Exchange rate 120[yen/$]
Source; TEPCO 1997, ANRE 1997, IERJ 1997, Dornbusch 1991, Flavin 1994

4. TECHNOLOGY CHOICE

This chapter discusses technology choice. It begins by defining the objective function of technology choice, and then it estimates the risk of nuclear power plant development in terms of CO2 control within a specific time horizon. Next, it proposes the strategies for reducing the risk. And, finally, it develops a framework to incorporate uncertainty into technology choice and demonstrates the risk-cost tradeoff of technology choice.

4.1 OBJECTIVE FUNCTION OF TECHNOLOGY CHOICE

Cost-effectiveness is a prerequisite of CO2 control technology. At the same time, CO2 control has to be implemented within the time limit set up in the COP3. Therefore, technology choice can be described as:

Minimize: Costs of Control

Subject to: Quantity of CO2 and Limit on Time

The essential point of this definition is that the cost-minimum choice is not always the optimal choice when a time limit is imposed. Technologies whose costs are low but that are not guaranteed the unfailing implementations, are a risky choice. By way of contrast, technologies whose costs are high but have a guaranteed implementation within a time limit, can be a reasonable choice. Essentially, there is a trade-off between cost-effectiveness and viability of technology options. It is this dilemma that nuclear power is now facing.

As discussed in Chapter 2, nuclear power is facing difficulty in siting plants. The difficulty makes the lead-time of nuclear power plant development long and volatile. The long and volatile lead-time could be because of uncertainty over the implementation of CO2 controls within a specific time period. The following sections explore the lead-time of nuclear power development and develop a framework to incorporate uncertainty into technology choice.

4.2 Lead-time for Nuclear Power Plant Development

For CO2 control, the problems of the lead-time are two-fold:

- When the lead-time turns out to be longer than a given time period, nuclear power can not contribute to CO2 control or to compliance with the agreement of the COP3.
- The volatility of the lead-time makes the implementation of CO2 control uncertain.

The two problems are similar, but not identical. The latter means that, even when the average of the lead-time is shorter than the time limit, the utilities still bear the risk that they can not control CO2 emissions within a given time period.

Lengthening Lead-times

Figure 4-1 outlines the procedures of nuclear power plant development. The procedure consists of three phases: finding a site for a power station and the examination of the Electric Power Development Coordination Council (EPDCC); the issuance of construction permits; and actual construction of a power station. The EPDCC examines the necessity of power plant development in terms of electricity supply and approves the plan of power plant development. The Atomic Energy Commission (AEC) and the Nuclear Safety Commission (NSC) then examines the safety of nuclear power reactors and issue the construction permits. Figure 4-2 itemizes the lead-time for nuclear power plant development (MITI 1995 and Suetugu 1994). In the 1970's, the average lead-time was 8.3 years and rose to 17.4 years in the 1980's, and is approaching 25.7 years in the 1990's.

The lengthiest portion of the lead-time is devoted to finding sites for new power stations. The period of 16 years accounts for 63% of the overall lead-time. There are three main reasons behind the difficulty in finding sites. First, the utilities have to secure the consent of the residents and the local governments to carry out an environmental impact assessment. Particularly, it requires the consent of more than half of the fishery cooperatives that will lose their fishery rights. Second, when the assessment is carried out and the results are approved by the national government, the utilities have to purchase a lot for a power station as well as gain fishery rights. Finding a site is often bogged down in the concession of fishery rights. Conceding fishery rights to the utilities requires the consent of more than two-thirds of the fishery cooperatives. Finally, when fishery rights are conceded, the utilities have to secure the consent of a prefecture governor. Until the residents and the local governments give their consent to build a nuclear power station, the utilities can not present a plan for nuclear power plant development to the EPDCC.

Once the utilities gain the necessary consent, the utilities propose a power station development plan to the EPDCC. The EPDCC then examines the necessity of power plants in terms of electricity supply. When the EPDCC approves the plan, the MITI, the AEC, and the NSC examine the safety of nuclear power reactors. The AEC and the NSC, which are established by the Atomic Energy Basic Law, issue construction permits with the consent of the Prime Minister. The period from the EPDCC's examination to the issuance of construction permits is normally three years. When construction permits are issued, the utilities begin to construct a power station. It usually takes about five years to construct a power station.

When the utilities build additional nuclear power plants in an existing power station, it is neither necessary to purchase lots for power plants nor gain fishery rights[6]. In this case, the lead-time is shorter than that necessary to build new power stations. The leading utility of Japan, the Tokyo Electric Power Company, operates 17 nuclear power plants in 3 nuclear power stations, and their nuclear power stations have 6 plants on average. These plants are built in sequence in response to the increase in electricity demand. The lead-time to construct the first plant is longer than those of the second and subsequent plants.

According to past statistics, if the utilities plan to build a nuclear power station today, the first plant will be commissioned 25.7 years later or in the year 2023. The agreement of the COP3 stipulates that CO_2 emission should be reduced by 2008 or 2012. To do so, the utilities have to devote unusual effort to shorten the lead-time of nuclear power plant development.

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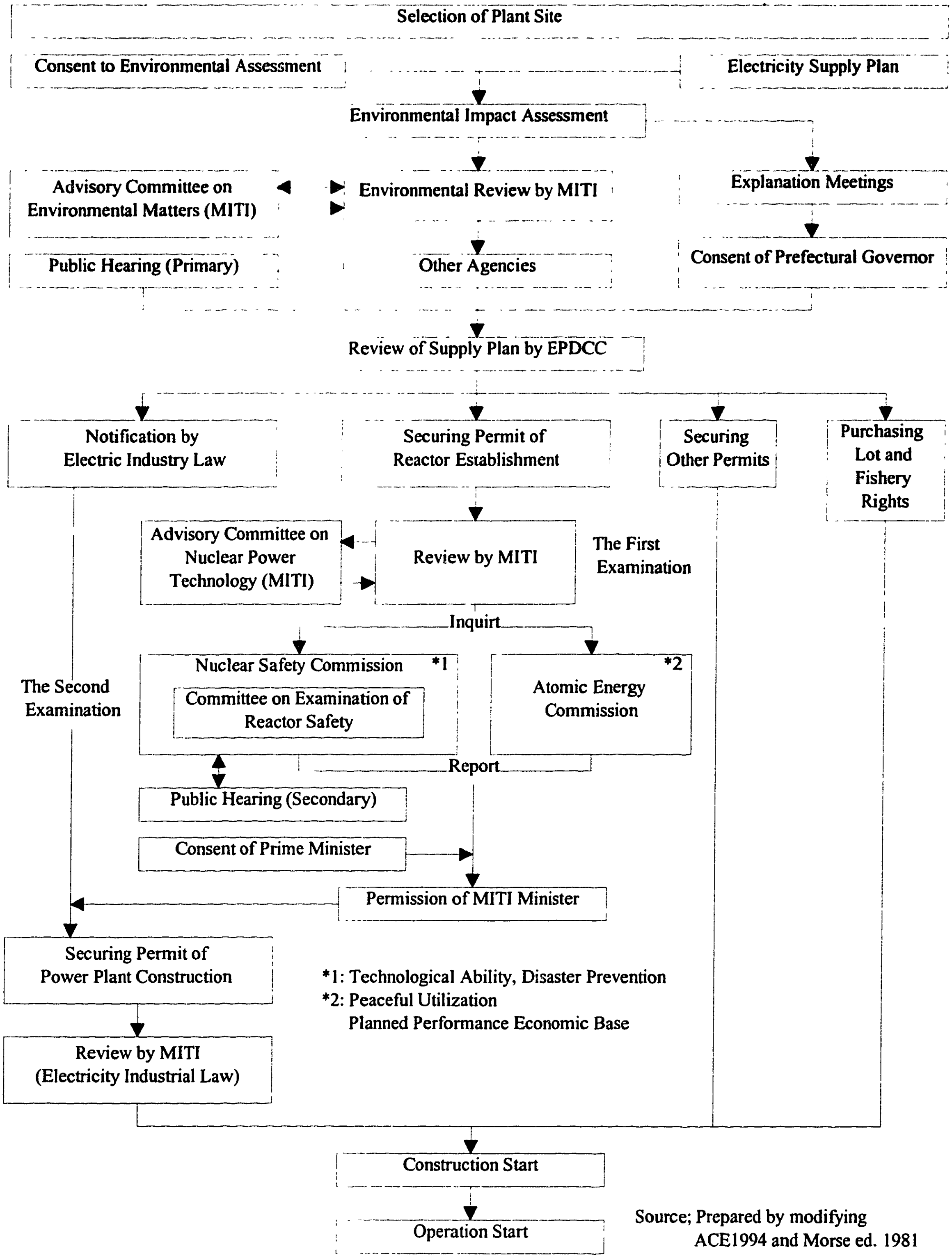
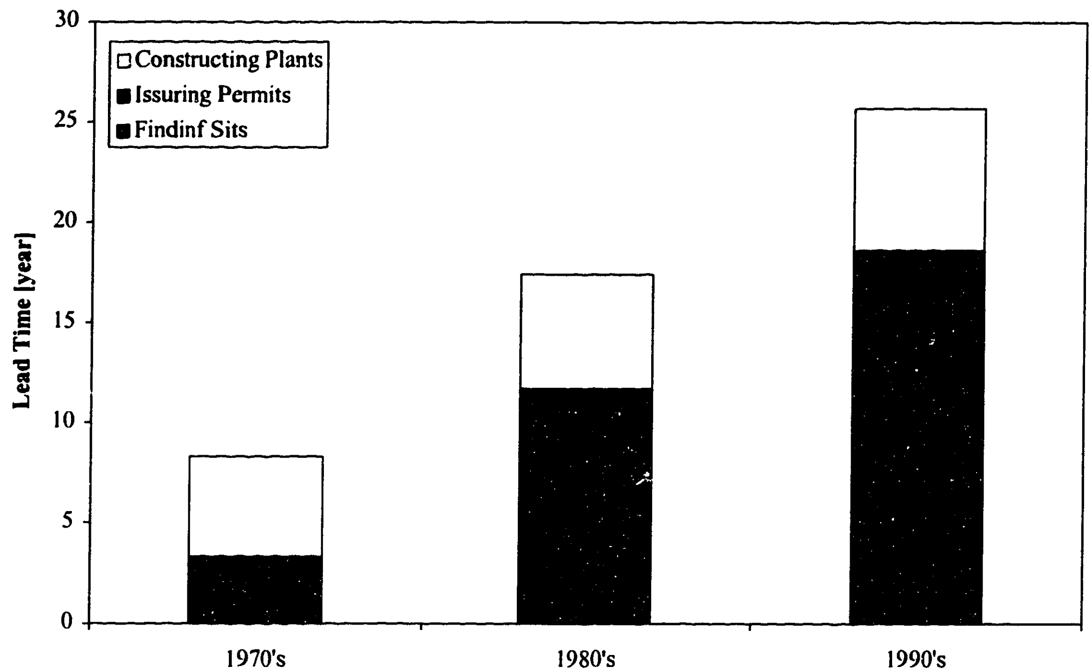
[6] Usually, the utilities pay additional compensation to fishery cooperatives because of the increased sea areas that may be affected by the power station.



Source; Prepared by modifying ACE1994 and Morse ed. 1981

Figure 4-1 Outline of Procedures of Nuclear Power Plant Development



Sources; ANRE 1992, JEA 1996

Figure 4-2 Lead-time for Nuclear Power Station Development

Volatility of Lead-time

The large part of the lead-time is to find sites for power stations. If the utilities have already purchased lots for power stations and fishery rights or if they build additional plants in the existing power stations, the average lead-time is about 8 years. Consequently, the plants commissioned today are expected to go into operation 8 years later or in the year 2006. However, not all plants are guaranteed operability within 8 years due to the volatility of the lead-time.

Such volatility is because the consent of the residents and the local government dose not always mean the consent of proprietors of building lots. For instance, the Tohoku Electric Power Company announced the plan of the Maki nuclear power station in 1971. A perceptual governor gave consent to the plan and the EPDCC approved the plan in 1981. Nevertheless, the utility has yet to purchase a part of the lot for the power station. The area is 1,700 m^2 (0.42 acres), or less than 0.1% of the total area of the power station (Suetugu, 1994).

Figure 4-3 shows the distribution of lead-times from the issuance of permits to commissioning plants (JAE, 1996). No data about the distribution of the entire lead-time are available. The lead-time from the issuance of permits to commissioning plants is a lognormal distribution, where a logarithm of the lead-time is normally distributed:

$$F(t) = \int_0^t \frac{1}{\sigma\sqrt{2\pi}} \cdot \frac{1}{x} \cdot e^{-\frac{(\ln(x)-\mu)^2}{2\sigma^2}} dx$$

where

F(t) = the probability distribution function [-]

t = the lead-time [years]

σ = the standard deviation of logarithms of the lead-time

μ = the average of logarithms of the lead-time

The probability distribution function, "***F(t)***," describes the probability that the lead-time is from 0 to ***t*** years. The average of logarithms of the lead-time, "μ", is 2.02, that is equal to 7.6 years. The standard deviation, "σ", is 0.27. The past statistics indicates that half of 53 plants were commissioned within 7.6 years from the EPDCC's approval while 5% of them were commissioned more than 11.7 years later from the EPDCC's approval.

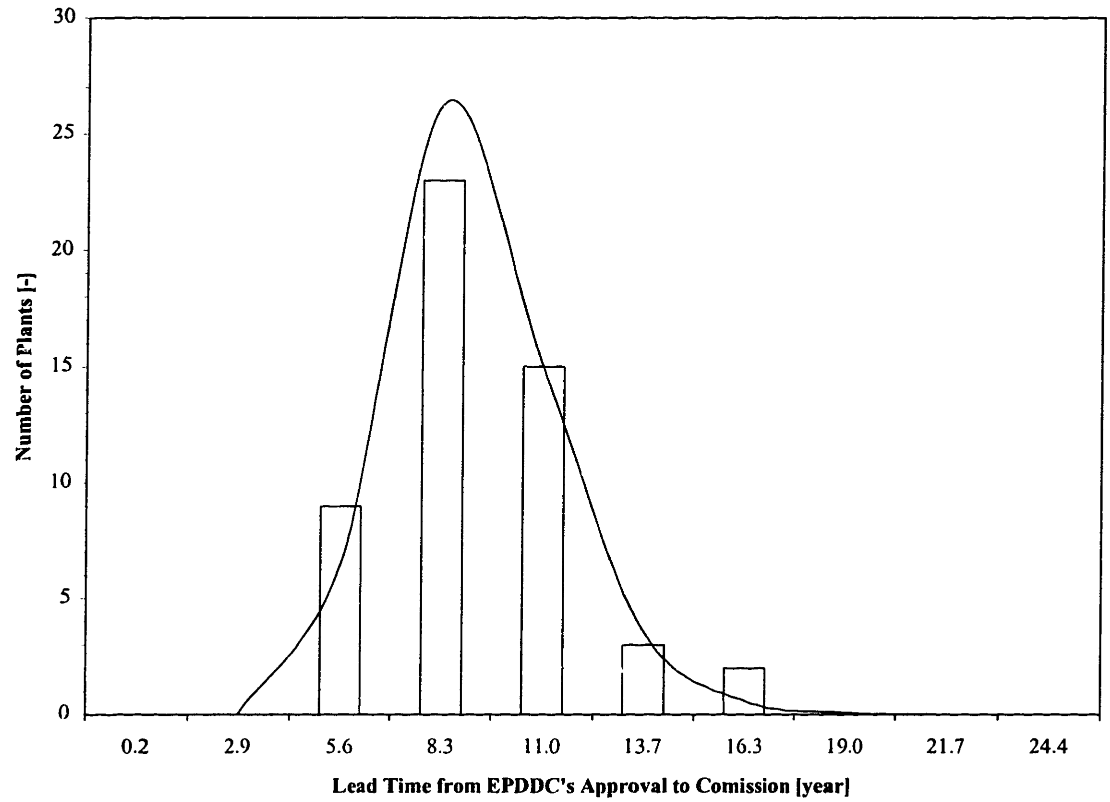


Figure 4-3 Distribution of Lead-time of Nuclear Power Plant Development

4.3 ANALYZING RISKS OF LONG LEAD-TIME

The risk of nuclear power is that the utilities fail to commission newly built plants within a given time period. This section estimates the risk in such action. The risk depends on many things, but 3 factors predominate. First, the time limit directly affects the risk. When the time limit is long enough to build nuclear power plants, the utilities can ignore the risk.

Second, the risk depends on the status of ongoing projects. When the utilities have already purchased fishery rights and lots for new power stations or decide to build new plants in existing power stations, the plants could be built within a relatively short time period, which reduces the risk. By contrast, it would take a long time to commission the plants if the utilities building new power stations have not yet received the consent of the residents and the local government. In this case, the risk increases.

Third, the more plants necessary for CO2 control, the lower the probability of all plants going into operation within the time limit. In other words, when the utilities increase the number of plants to be built, the probability that some of them are not commissioned within a given time period increases. Let a project probability, "***F***," denote the individual probability of a plant being commissioned within a given time period. Similarly, let a system probability, "***P***," denote the overall probability that all plants necessary for CO2 control are commissioned. For instance, when each plant has a project probability of 0.5 and two plants are necessary for CO2 control, a system probability can be obtained by the production of project probabilities: $\boldsymbol{P} = \boldsymbol{F} \times \boldsymbol{F} = 0.5 \times 0.5 = 0.25$. A system probability depends on both the project probability of each plant and the number of necessary plants.

Time Limit

As discussed in Chapter 1, the COP3 set up the time table for CO2 control. Japan and other developed countries have to reduce CO2 emissions in the period 2008 to 2012. For simplicity, it is assumed that the utilities reduce CO2 emission in the year 2012. To do so, the utilities have to build nuclear power plants before the year 2012. The time limit for building plants is the year 2011 and there are 13 years before the time limit. The time limit of 13 years is shorter than the entire lead-time from finding sites to constructing plants (25.7 years), while it is longer than the lead-time for the issuance of construction permits and actual construction (7.6 years). Thus, a critical issue is how many projects have already received the consent of the residents and the local governments.

Ongoing Projects

In 1997, while 5 nuclear power plants were closed down in the world, 2 plants were commissioned in Japan. As a result, Japan operates 53 plants[7] whose total capacity is 45.248 million kW. That accounts for 12% of the total number and the total capacity of the world (JAIF, 1998).

Table 4-1 lists ongoing projects of nuclear power plant development. As of 1998, one plant is under construction and 4 plants have been approved by the EPDCC and are waiting for construction permits to be issued from the national government. In addition, the EPDCC is examining another 5 projects. A total of 10 plants have already received the consent of the residents and the local government. In addition to these ten plants, the utilities have announced plans to build another 10 plants, which have not yet received the consent of residents and local governments. Therefore,

[7] The Japan Atomic Power Company decommissioned on March 31, 1998 a reactor built in 1966, which was the first reactor built in Japan.

there are 20 ongoing nuclear power plant projects, which matches the prospect that the MITI expects to build by 2010.

However, there is clear nationwide uncertainty about ongoing projects. For instance, as shown in Chapter 2, the inhabitant's poll blocked the project of the Maki nuclear power station. In addition, the recent scandalous incidents of the Power Reactor and Nuclear Fuel Development Corporation deeply eroded the public trust in nuclear power policy and technology.

Therefore, the utilities have reservations about the future of ongoing projects. An expert of the utilities said: "11 of 20 plants are the best we can do." (Asahi Shinbun, 1998). The view of the experts roughly matches the number of projects that have already received consent.

Table 4-1 Ongoing Projects of Nuclear Power Development

Utility	Unit	Capacity [MW]	Planned Commission
Under constraction			
1 Tohoku	Onagawa #3	825	Jan-2002
Issuing Permits			
* 2 Tohoku	Higashidori #1	1,100	Jul-2005
* 3 Tohoku	Maki #1	825	**
4 Chubu	Hamaoka #5	1,380	Aug-2005
5 Hokuriku	Shika #2	1,358	Mar-2006
EPDCC examination			
6 Tokyo	Fukushima Daiich #7	1,380	2005
7 Tokyo	Fukushima Daiich #8	1,380	2006
* 8 Chugoku	Kaminoseki #1	1,373	2007
* 9 Chugoku	Kaminoseki #2	1,373	2010
* 10 EPDC	Oma #1	1,383	2006
Planned			
11 Tokyo	Higashidori #1	1,100	2004
12 Tokyo	Higashidori #2	1,100	2005
* 13 Chubu	Ashihama #1	1,350	2004
* 14 Chubu	Ashihama #2	1,350	2004
* 15 Tohoku	Namie.Odaka #1	1,100	2004
16 Tohoku	Higashidori #2	1,100	2005
17 JAPC	Turuga #3	n.a.	n.a.
18 JAPC	Turuga #4	n.a.	n.a.
19 Chugoku	Shimane #2	n.a.	n.a.
* 20 Kyushu	Kushima	n.a.	n.a.

* New Sits EPDC; Electric Power Development Co., Ltd.
** See Chapter 2 JAPC; Japan Atomic Power Company
Source; Suetsugu 1994, JEA 1997, STA 1998

Model Scenario

For simplicity, this thesis assumes the following scenario: first, the utilities build 20 nuclear power plants by 2011 to control CO2 emissions (this is the same scenario as the long-term energy supply and demand outlook prepared by the Advisory Committee for Energy); second, to do so, the utilities build two plants each year from 2002 to 2011 (because the next plant is expected to go into operation in 2002, no plant is commissioned before 2002); third, no nuclear power plant is closed down until 2012[8]. As a result, 73 nuclear power plants will be running in 2012. Figure 4-4 shows the past development of nuclear power plants, the ongoing projects listed in Table 4-1, and the scenario assumed here.

This scenario assumes that the capacity of a nuclear power plant is 1,350 MW and the utilization rate is 80% so that the annual output is 9,460 GWh. Assuming that, existing plants and 20 newly built plants will supply the electricity that the long-term supply and demand outlook expects.

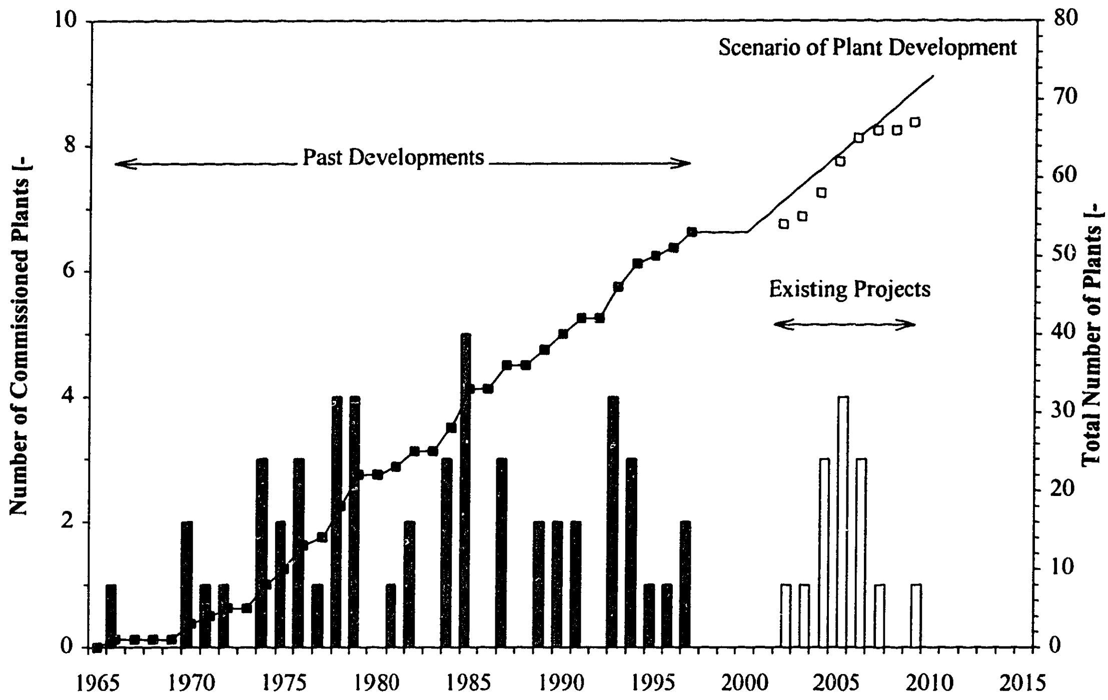


Figure 4-4 Trend and Scenario of Nuclear Power Development

[8] The Japan Atomic Power Company decommissioned on March 31, 1998 a reactor built in 1966, which was the first reactor built in Japan.

Over the past 32 years, Japan built 53 nuclear power plants. The average rate of building plants is 1.65 plants per a year. The building rate of two plants per year is higher than the past average. As discussed in Chapter 2, building nuclear power plants is getting tougher and tougher. Even if the utilities dedicate their best efforts, building 2 plants each year will be a daunting challenge for them.

Estimating Risk

The scenario is a "plan," however. The implementation of the plan would be affected by the volatility of the lead-time, and the system probability of the plan depends on project probabilities of the scenario.

First, the lead-time of plants approved by the EPDCC is lognomaly distributed. Project probabilities of them can be estimated from a probability distribution function. For instance, plants approved in 1997 have 14 years before 2012. A project probability for them is estimated as:

$$F(14) = \int_0^{14} \frac{1}{0.266\sqrt{2\pi}} \cdot \frac{1}{x} \cdot e^{-\frac{(\ln(x)-2.02)^2}{2\times 0.266^2}} dx = 0.9898$$

In this case, the utilities can reasonably ignore the risk of failing to commission the plants because the probability is almost 1. For this reason, while five plants have already been approved by the EPDCC, four of them are reasonably expected to go into operation not later than 2011. The one exception is the Maki nuclear power station, which was discussed above.

In addition, the EPDCC are examining five plants now and are expected to approve them within 1 or 2 years. Thus, they also can be expected to go into operation before 2011[9]. In all, 9 plants are assumed to be commissioned not later than 2011.

Assuming that 9 plants are commissioned, the system probability of the scenario is equal to the probability that the rest of the 11 plants go into operation not later than 2011. In other words, the variability of CO2 control depends on project probabilities of the 11 plants. Building 11 plants is clearly a serious challenge to the utilities. Therefore, it is difficult to estimate the probability of 11 plants going into operation before 2011. First, a series of recent scandals and a poll of the inhabitants make the future of nuclear power unpredictable. Second, the current situation of each project is not disclosed. Some projects may be close to receiving the consent of the residents and the local governments, while others may have just began the process. Third, no information is available on the distribution of the lead-time before the EPDCC's examination. The only available data are the averages of the lead-time as shown in Figure 4-3.

On the contrary, although it is difficult to accurately estimate project probabilities of actual plants, it is possible to calculate back to the necessary condition for CO_2 control. For instance, when a plant is commissioned with a project probability of 0.9, a system probability of two plants being commissioned is obtained from the production of the project probabilities: $0.9 \times 0.9 = 0.81$. Conversely, when a system probability of two plants is 0.81, a project probability of each plant is obtained from the inverse operation: $0.81^{1/2} = 0.9$. In that case, when the utilities ensure CO_2 control with a probability of 0.81, each plant needs to be built with a probability of 0.9.

Generally, when a system probability is given, project probabilities can be obtained from the inverse function of the system probability. In reality the utilities build not just one plant but sometimes more than two plants in a project. Therefore, a system probability depends on not the number of plants to be built but the number of projects to be launched:

$$P = F_1 \times F_2 \times \cdots \times F_n$$

where

P = the system probability that "***n***" projects commissioning plants not later than 2011.

Fi = the project probability of an "***i***-th" project commissioning plants not later than 2011

The number of independent projects depends on how many plants the utilities build in a project. The plants of the same project have the same lead-time because they simultaneously fall behind schedule due to the same difficulties, such as the purchase of a lot for a power station. Previous projects built one or two plants at a time. When each project builds one plant, 11 projects are necessary to build 11 plants. When each project builds two plants, 6 projects are necessary—5 projects build two plants and one project builds one plant. In the model scenario, the total number of projects is no more than 11 and no less than 6.

[9] In March 31 1998, the EDPC revised the schedule of the Oma nuclear power station due to the delay of the consent of fishery cooperatives. (Asahi Shinbun April 1 1998)

Clearly, different projects have different probabilities. For simplicity, ***n*** projects are assumed to have an identical probability. In that case, a project probability is obtained from the ***1/n***-th root of a system probability. For instance, when the utilities launch 6 projects and they ensure CO2 control with a system probability of 0.80, the necessary condition of each project is obtained from the one sixth root of 0.80; $0.80^{1/6}$=0.96. In that case, 6 projects need to have a project probability of not less than 0.96.

Figure 4-5 shows the necessary conditions of four cases—system probabilities are equal to 0.90, 0.80, 0.70, and 0.60. It is not the intention of this thesis to discuss what system probability is enough to ensure CO2 control. However, even when a "fifty-fifty chance" is enough for CO2 control, each project still needs to have a project probability of 0.94 for 11 projects, 0.89 for 6 projects. Generally, it is safe to say that a "fifty-fifty chance" is not high enough to comply with the agreement of the COP3. Nevertheless, the way things stand now, a project probability of 0.94 or 0.89 may not be realistic. Indeed, if each project had a project probability of 0.90, the utilities industry would not mention a concern about the future of nuclear power plant development.

Moreover, what matters most is that a system probability is always less than the smallest project-probability among all projects. For instance, when all projects have a project probability of 1.0 but only one project has that of 0.5, a system probability decreases to 0.5. In other words, the overall risk strongly depends on the most risky project. Thus, even when the risks of most projects are negligible, but one project is risky, reducing the risk is "a must" for CO2 control.

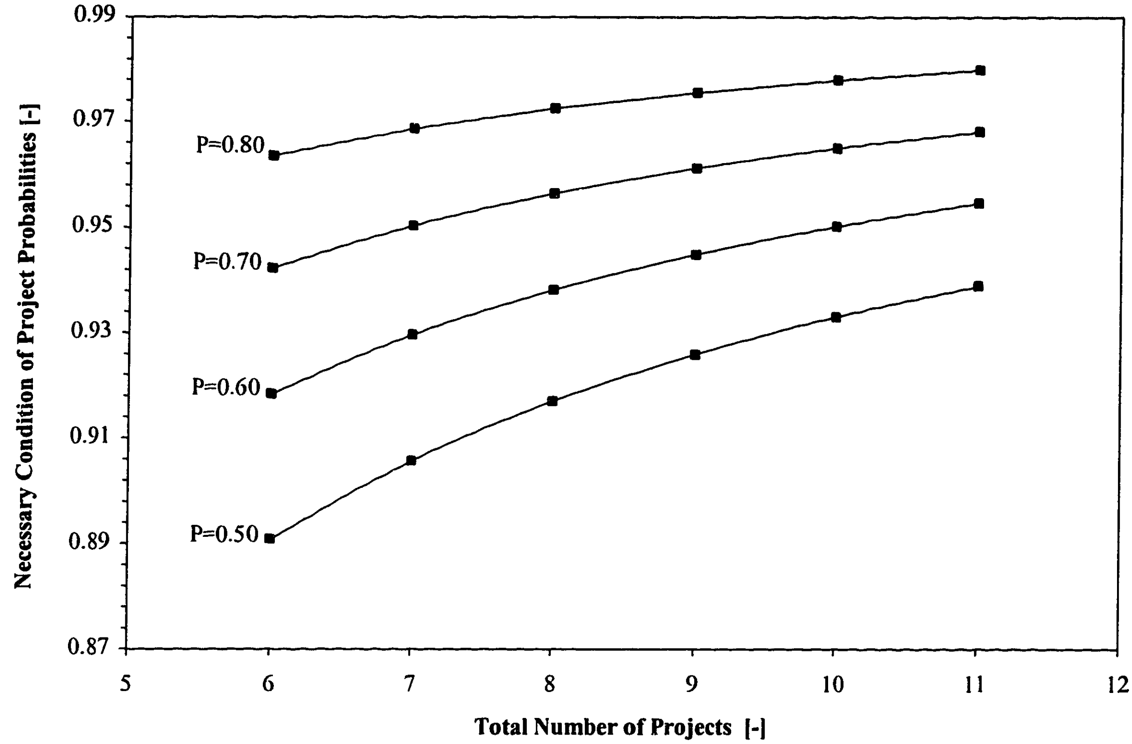


Figure 4-5 Necessary Probability of Each Project

4.4 REDUCING RISK

The analysis of a system probability shows that nuclear power is a risky option as long as uncertainty attaches to the lead-time. That, however, does not diminish the necessity of nuclear power plant development. On the contrary, the more risky nuclear power plant development is, the more concentrated effort the utilities need to make up for that risk.

At the same time, when risk is not negligible, reducing the risk is indispensable in ensuring CO2 control. Foe this purpose, the following sections discusses strategies for reducing the risk of technology choice. The basic strategies are to set up technology portfolios that combine nuclear power and low-risk technologies.

Strategies for Reducing Risk

Nuclear power has the long and volatile lead-time that makes CO2 control uncertainty. In contrast, energy sources such as wind power have less difficulty in siting plants and, therefore, more predictable lead-time than nuclear power. For this reason, combining these two technology options can reduce the risk of failing CO2 control. The following part of this section discusses the combinations of nuclear power and new energy power, or "technology portfolios", in terms of the risk reduction.

Though the development of new energy power plants does have some difficulties[10], for simplicity we will assume that they can be built anytime the utilities want. To ensure CO2 control, the utilities are assumed to combine nuclear power plants and new energy power plants. The possible combinations are:

a) building more than 20 nuclear power plants

b) substituting some new energy power plants for a part of 20 nuclear power plants

c) building some new energy power plants and 20 nuclear power plants

d) building another combination of new energy power plants and nuclear power plants

<u>a) Building More Than 20 Nuclear Power Plants</u>

The first strategy is just to launch additional projects of nuclear power. For instance, when the utilities launch additional projects to build total 21 nuclear power plants, the system probability of <u>all</u> 21 plants being commissioned is less than that of 20 plants. However, a system probability of <u>at least</u> 20 plants being commissioned is higher than that of 20 plants. In other words, even when the utilities fail to commission one plant, they have still a chance to commission 20 plants. In this sense, additional plants can be seen as a type of insurance.

This argument, however, holds good when all projects are independent each other. For instance, when a movement against nuclear power plants in a certain region affects other projects in other regions, project probabilities of each project are no longer independent. Similarly, when the utilities build plants in a power station one by one, the latter plants can not be built until the former plants are built. Likewise, when the utilities build plants in different power stations but have to secure the consent of the same local government, it is often difficult to receive the consent of the latter projects until the local government gives the consent of the first projects. In those cases, launching additional projects does not enhance a system probability.

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[10] The municipal-waste-burning power generation has the some similar difficulty in siting power plants as nuclear power does.

In addition, the utilities are reasonably assumed to launch "easy" projects first and "tough" ones later. This is because the lead-time of tough projects is longer than those of easy ones and, consequently, the costs of the former are higher than those of the latter. To minimize the cost of power development, the utilities build plants in order of increasing difficulty. For this reason, additional projects are always more risky than ongoing projects and project probabilities of the former are always lower than those of the most risky ongoing projects. Therefore, although launching additional projects enhances the system probability, the contribution may not be large.

b) Substituting New Energy Power for Nuclear Power

By contrast, building new energy power plants always increases a system probability and decreases the risk of failing to commission 20 plants because of the predictable lead-time. For instance, when the utilities build a new energy power plant and 19 nuclear power plants, a system probability is equal to that of 19 nuclear power plants being commissioned because a new energy power has a project probability of 1.0. The substitution of new energy power plants for nuclear power plants simply reduces the risk of nuclear power projects and enhances the system probability.

c) Building Additional New Energy Power Plants

When the utilities build new energy power plants in addition to 20 nuclear power plants, that reduces the necessary number of nuclear power plants to control CO2. For instance, when the utilities build one new energy power plant and 20 nuclear power plants, 19 nuclear power plants are enough to control CO2. In that case, a system probability is equal to that of at least 19 nuclear power plants being commissioned. In other words, the utilities can fail to commission one of twenty plants. Reducing the necessary number of nuclear power plants enhances the system probability.

d) Combining New Energy and Nuclear Power

Strategy (d) involves any possible combination of nuclear power plants and new energy power plants. The common strategy of technology portfolios is to reduce the ratio of the necessary number to the total number of nuclear power plants. For Instance, when the utilities build 2 new energy power plants and 19 nuclear power plants, a system probability is equal to that of at least 18 of 19 nuclear power plants being commissioned.

Reducing Risk

As shown in Section 4.3, the system probability of CO2 control depends on the number of projects. Thus, the following part of this section analyzes a system probability based on the number of projects. As discussed in Section 4.3, the total number of projects is from 6 to 11, depending on the average number of plants involved in a project.

For instance, when 6 nuclear power projects are necessary for CO2 control and 6 projects have the same probability of 0.90, a system probability of all six projects being commissioned is 0.53:

$$P\left(\frac{6}{6}\right) = F^6 = 0.9^6 = 0.5314$$

where

$P\left(\frac{n}{N}\right)$ = the system probability that "*n*" of "*N*" projects going into operation

${}_N C_n \equiv \frac{N!}{n! \cdot (N-n)!}$ = the number of combinations of "*n*" pulled from "*N*."

F = the project probability of a project going into operation

A system probability of 0.53 is almost a "fifty-fifty" chance. On the other hand, an additional project of new energy power decreases nuclear power projects necessary for CO2 control from 6 projects to 5 projects. In that case, a system probability of at least 5 nuclear power projects being commissioned is obtained from the sum of the probability of 5 projects being commissioned and that of 6 projects:

$$P\left(\frac{5}{6}\right) = {}_6C_5 \cdot F^5 \cdot (1-F)^1 = 7 \times 0.9^5 \times (1-0.9)^1 = 0.3543$$

$$\therefore \quad P\left(\frac{5 \sim 6}{6}\right) = P\left(\frac{5}{6}\right) + P\left(\frac{6}{6}\right) = 03542 + 0.5314 = 0.8857$$

An additional project of new energy power enhances a system probability from 0.53 to 0.89. This is an example of Strategy (c).

In general, when each nuclear power project has a project probability of "*F*," a system probability of "*P*" is obtained from:

$$P\left(\frac{(L-M)\sim N}{N}\right)=\sum_{n=L-M}^{N} P\left(\frac{n}{N}\right)$$

$$P\left(\frac{n}{N}\right)={}_{N}C_{n}\cdot F^{n}\cdot(1-F)^{N-n}$$

where

L = the number of projects necessary for CO2 control

M = the number of new energy power projects

N = the number of nuclear power projects

Table 4-2 Strategies for Reducing Risk

Strategy	New energy power plants M		Nuclear power plants N
a)	M=0		N>L
b)		M+N=L	
c)	M>0		N=L
d)		M+N>L	

L; the number of projects necessary for CO2 control

Table 4-2 summarizes the strategies and Table 4-3 ~ Table 4-5 shows the results of the risk reductions. Table 4-3 is the same case discussed above. Six nuclear power projects are necessary for CO2 control and a project probability of each project is 0.9. Table 4-4 is the case where project probabilities of nuclear power projects are 0.6. Table 4-5 is the case where 11 nuclear power projects have a project probability of 0.9. Table 4-4 shows that a system probability is diminished to less than 0.047 when 6 nuclear power projects have a project probability of 0.6 and the utilities launch no new energy projects. In contrast, an additional new energy project increases it from 0.047 to 0.233 by 5 times.

Figure 4-6 shows the results of enhancing system probabilities. First, no matter what projects are added, adding projects enhances system probabilities more effectively than substituting new energy power projects for nuclear power projects. Therefore, it is not advisable to drop ongoing nuclear power projects even when they have a small project probability, say 0.6. Indeed, sooner or later, ongoing projects become necessary to satisfy ever-increasing demand. Unless the utilities begin actual construction of power plants, the cost of pursuing ongoing projects is nominal compared with the total cost of power plant development. For these reasons, the substitution of new energy projects (Strategy (b)) is neither effective nor practical for reducing risk.

Second, additional new energy projects always enhance a system probability more effectively than additional nuclear power projects. This is because project probabilities of new energy projects are 1.0, while those of nuclear power projects are less than 1.0. In addition, although all nuclear power projects, including additional projects, are assumed to have an identical project probability, each project can have a different project probability in realty. Therefore, the utilities launch easy projects fast and tough ones later and additional nuclear power projects have smaller probabilities than ongoing projects. For this reason, when the utilities launch additional nuclear power projects, the system probabilities are indicted by the lines of M=0 but the lines indicate the upper limits of system probabilities.

In contrast, when project probabilities of nuclear power projects are not uniform, adding new energy projects enhances system probabilities more effectively than when nuclear power projects have an identical project probability. This is because system probabilities depends strongly on the most risky project. For instance, when 5 of 6 nuclear power projects have a project probability of 1.0 but one of them has a probability of 0.531, the system probability is 0.531. Similarly, when 6 projects each have a project probability of 0.9, the system probability is 0.531. In those cases, adding a new energy project enhances the system probability from 0.531 to 0.951 in the former case, to 0.886 in the latter case. Consequently, the lines of M=1 and M=2 indicate the lower limit of system probabilities of adding new energy projects. Foe this reason, adding new energy projects (Strategy (c)) is more effective than adding nuclear power projects (Strategy (a)).

In conclusion, it is not advisable to either drop or add nuclear power projects. The most effective strategy is to launch additional new energy projects. That is, Strategy (c) is most advisable among Strategies (a), (b), (c), and (d).

Table 4-3 Overall Probability (L=6, F=0.9)

		M		
		0	1	2
	5	-	0.590	0.919
N	6	0.531	0.886	0.984
	7	0.850	0.974	0.997

N; Numbrt of Nuclear Power Projects

M; Number of New Energy Power Projects

Table 4-4 Overall Probability (L=6, F=0.6)

		M		
		0	1	2
	5	-	0.078	0.337
N	6	0.047	0.233	0.544
	7	0.159	0.420	0.710

N; Numbrt of Nuclear Power Projects

M; Number of New Energy Power Projects

Table 4-5 Overall Probability (L=11, F=0.9)

		M				
		0	1	2	3	4
	9	-	-	0.387	0.775	0.947
	10	-	0.349	0.736	0.930	0.987
N	11	0.314	0.697	0.910	0.981	0.997
	12	0.659	0.889	0.974	0.996	0.999
	13	0.866	0.966	0.994	0.999	1.000

N; Numbrt of Nuclear Power Projects

M; Number of New Energy Power Projects

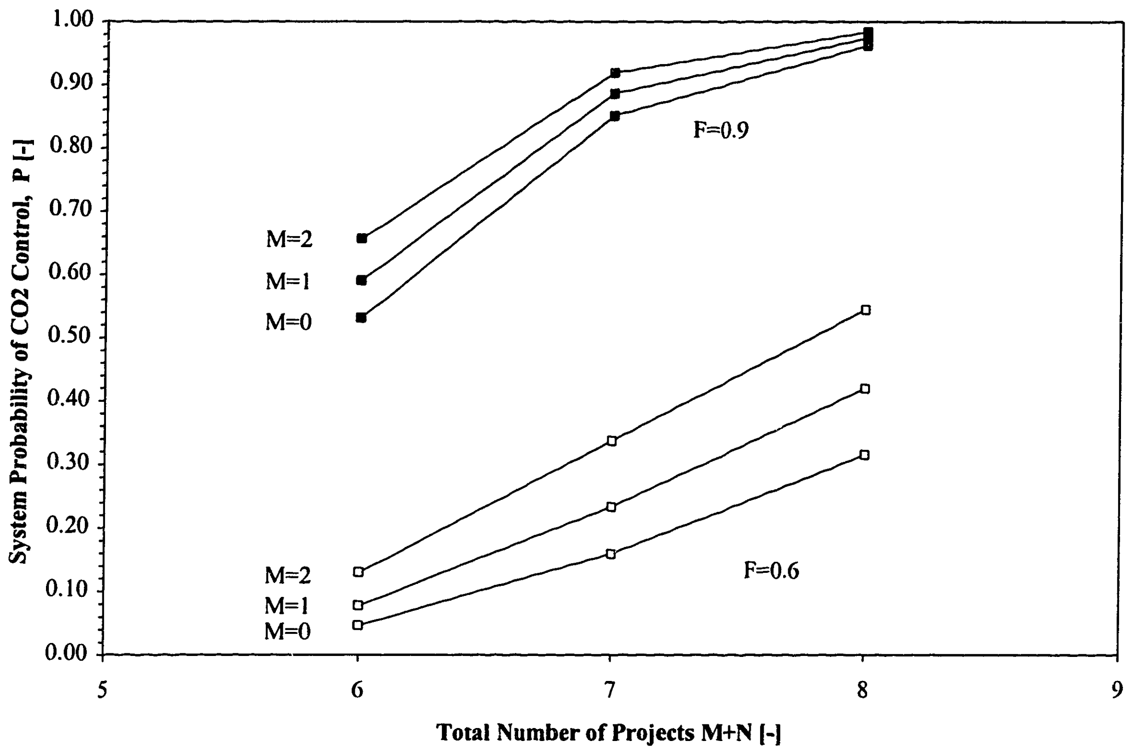


Figure 4-6 Enhancing Overall Probability (L=6)

4.5 ANALYZING THE TRADE-OFF BETWEEN COST-EFFECTIVENESS AND RISK

The analysis of risk control strategies reveals that new energies reduce the risk of failing CO2 control mainly due to the predictable lead-time. New energy sources, however, raises the cost of power generation and, consequently, the cost of CO2 abatement. The optimal technology choice depends on the trade-off between cost-effectiveness and risk. This section develops and demonstrates a framework to incorporate the trade-off into technology choice.

Methodology

The basic methodology used to evaluate the trade-off is the discounted cash flow analysis (DCF), which calculates the present value of the profit in power generation. The profit, however, is subject to uncertainty due to the volatility in the lead-time. To incorporate uncertainty into technology choice, the analysis estimates the expected mean value of the profit, assuming the probability distribution function of the lead-time.

Though the expected mean value is the most likely value of the profit, the actual profit may fluctuate around it. Therefore, the analysis estimates the standard deviation and the interquartile range of the profit, assuming first order approximation, or *Gaussian* approximation.

Third, the profit depends on assumptions such as the average lead-time and cost of new energy power generation. The scenario analysis and the sensitivity analysis of important parameters are performed to show how assumptions affect technology choice.

The analysis estimates the expected mean value of CO2 emissions as well as profit. The goal of the analysis is to shed light on the trade-off between cost-effectiveness and risks of technology choice. To this end, the analysis plots the relationship between the expected profit and system probabilities of CO2 controls or expected CO2 emissions.

Discounted Cash Flow Analysis

The discounted cash flow analysis adopted in this thesis consists of four parts:

- Assumptions of electricity demand
- Probabilities of nuclear power plant development
- Expected mean value of profit
- Present values of expected profit

Assumptions of Demand and Purchase of Make-up Electricity

DCF analysis adopts the same assumptions as Section 4.3 and 4.4. The utilities build 20 nuclear power plants between 2002 and 2011, 9 of which are commissioned by 2006. The DCF analysis assesses the profits and risks of the remaining 11 plants. For simplicity, 6 independent projects are assumed to build 11 plants from 2006 to 2011. Consequently, each project builds 1.83 plants on average or produces 9460×1.83=17,340 GWh per year. The demand of electricity is described as:

$$D(t) = \begin{cases} 0 & t = 0 \sim 7 \ (1998 \sim 2005) \\ 17{,}340 \times (t-7) & t = 8 \sim 13 \ (2006 \sim 2011) \\ 17{,}340 \times 6 = 104{,}040 & t = 14 \sim \ (2012 \sim \quad) \end{cases}$$

where

D(t) = the annual demand of electricity [GWh/year]

As discussed in Section 4.4, launching additional new energy projects is the most effective strategy for reducing risks. For this reason, the utilities are assumed to launch additional new energy projects instead of dropping or adding nuclear power projects. We assume that new energy power plants are commissioned by the year 2011.

The output of nuclear power plants is obtained from the expected mean value of the installed capacity. When the total output of nuclear power plants and new energy power plants is smaller than the demand of electricity, the utilities purchase electricity from independent power producers to make up the capacity deficit. When the utilities purchase electricity from the year 2012 onward, the utilities have to pay the penalty for emitting CO2 because independent power producers produce make-up electricity from fossil fuels, emitting CO2 into the atmosphere.

The DCF analysis assumes two contracts to purchase make-up electricity; a one-year contract and a long-term contract. Under a one-year or a short-term contact, the utilities can cancel the contract held with independent power producers when the utilities commission nuclear power plants. For instance, if the utilities commission no project in the year 2006, they hold the contract to purchase make-up electricity of 17,340 GWh. If two nuclear power plant projects are commission in the year 2007, they can satisfy the demand for the year 2007; therefore, the utilities cancel the contract held in 2006.

By contrast, under a long-term contract the utilities must continuously purchase electricity from independent power producers. In this example, once the utilities sign a contract for the year 2006, the utilities must also purchase the same amount of electricity in the year 2007, which would supply half of the demand. The output of nuclear power plants would supply the rest of the demand, even if two nuclear power plant projects are commissioned.

For both contracts, when the sum of nuclear power plants, new energy power plants and make-up electricity exceeds the demand, nuclear power plants reduce output while new energy power plants produce electricity at full capacity so that the total output balances the demand.

Probabilities of Nuclear Power Plant Development

Assuming that the lead-time of nuclear power projects is lognomaly distributed, project probabilities can be obtained from a probability distribution function. System probabilities, which are defined as " '***n***' of 6 projects are completed not later than 2011," are obtained from the product of project probabilities.

$$F(t) = \int_0^t \frac{1}{\sigma \cdot \sqrt{2\pi}} \cdot \frac{1}{x} \cdot e^{-\frac{(\ln(x)-\eta)^2}{2\sigma^2}} dx$$

$$P(n,t) = {}_6C_n \cdot F(t)^n \cdot (1 - F(t))^{6-n}$$

where

F(t) = the project probability that a project are completed not later than "***t***" [-]

P(n,t) = the system probability that "***n***" of 6 projects are completed not later than "***t***"[-]

Sort-Term Contract

Under a short-term or a one-year contract, the output of nuclear power plants depends on the number of projects commissioned. The output of new energy power plants are exogenously given by the strategy for reducing risk. The DCF analysis calculates the demand and the output of new energy. Then, it calculates the probabilities of nuclear power plant development and the expected mean values of the output of nuclear power projects. Finally, it calculates make-up electricity needed to satisfy the demand for electricity.

Expected mean values of profit

The cost of new energy power generation is easy to calculate because new energy projects have little uncertainty. Under a short-term contract, the utilities are assumed to have built all new energy plants by the year 2011. Their cost can be obtained by multiplying the unit cost of power generation by the output.

$$C_E(t) = \frac{c_E \times Q_E(t)}{1000}$$

$$Q_E(t) = \begin{cases} 0 & t = 0 \sim 12 \ (1998 \sim 2010) \\ 17{,}340 \times M & t = 13 \sim \ \ (2011 \sim \quad) \end{cases}$$

where

$C_E(t)$ = the cost of new energy power generation [billion yen]

c_E = the unit cost of new energy power generation [yen/kWh]

$Q_E(t)$ = the output of new energy projects [GWh]

M = the number of new energy power projects [-]

For nuclear power projects, the DCF analysis evaluates the expected mean values of their cost. They are obtained by multiplying the costs and the probabilities. Their output, however, is equal to the difference between the demand and the output of new energy projects when the total output exceeds the demand.

$$E(C_N(t)) = \sum_{n=0}^{6} C_N(n,t) \cdot P(n,t)$$

$$C_N(n,t) = \frac{c_N \times Q_N(n,t)}{1000}$$

$$Q_N(n,t) = \begin{cases} 17{,}340 \times n & 17{,}340 \times n \le D(t) - Q_E(t) \\ D(t) - Q_E(t) & 17{,}340 \times n \ge D(t) - Q_E(t) \end{cases}$$

where

$E(C_N(t))$ = the expected mean value of the cost of nuclear power generation [billion yen]

$C_N(n,t)$ = the generation cost of "*n*" nuclear power projects [billion yen]

c_N = the unit cost of nuclear power generation [yen/kWh]

$Q_N(n,t)$ = the output of "*n*" nuclear power projects [GWh]

The costs of make-up electricity and the penalties for emitting CO2 are similar to the costs of nuclear power generation because they depend on the expected mean value of nuclear power output.

$$E(C_M(t)) = \sum_{n=0}^{6} C_M(n,t) \cdot P(n,t)$$

$$C_M(n,t) = \frac{c_M \times Q_M(n,t)}{1000}$$

$$Q_M(n,t) = D(t) - Q_E(t) - Q_N(n,t)$$

where

$E(C_M(t))$ = the expected mean value of the cost of make-up electricity [billion yen]

$C_M(n,t)$ = the cost of make-up electricity when "*n*" nuclear power projects are completed [billion yen]

c_M = the unit cost of make-up electricity [yen/kWh]

$Q_M(n,t)$ = the quantity of make-up electricity when "*n*" nuclear power projects are completed [GWh]

The penalties depend on the charge of CO2 emissions per unit of carbon and CO2 intensity of make-up electricity:

$$E(C_P(t)) = \sum_{n=0}^{6} C_P(n,t) \cdot P(n,t)$$

$$C_P(n,t) = \frac{c_P \times Q_M(n,t)}{1000}$$

$$c_P = \begin{cases} 0 & t = 0 \sim 13 \ (1998 \sim 2011) \\ \dfrac{\eta \cdot y}{1000000} & t = 14 \sim \ \ (2012 \sim \quad) \end{cases}$$

where

$E(C_P(t))$ = the expected mean value of the penalty of emitting CO2[billion yen]

$C_P(n,t)$ = the penalty of emitting CO2 when "*n*" nuclear power projects are completed [billion yen]

c_P = the charge of CO2 emission per unit electricity [yen/kWh]

y = the charge of CO2 emission per unit carbon [yen/t-C]

η = the CO2 intensity of make-up electricity [g-C/kWh]

In addition to the cost of power generation, transmission and distribution costs are also considered. Because the total output is equal to the demand, other costs are obtained by multiplying the unit cost and the demand:

$$C_O(t) = \frac{c_O \times D(t)}{1000}$$

where

$C_O(t)$ = the other costs such as transmission and distribution [billion yen]

c_O = the unit other costs[yen/kWh]

Similarly, we obtain the revenue by multiplying the price of electricity by the demand:

$$R(t) = \frac{f \times D(t)}{1000}$$

where

$R(t)$ = the revenue of power generation [billion yen]

f = the price of electricity [yen/kWh]

The profit can be obtained from the difference between the revenue and the total costs:

$$G(t) = R(t) - C_T(t)$$

$$C_T(t) = C_E(t) + E(C_N(t)) + E(C_M(t)) + E(C_P(t)) + C_O(t)$$

where

$G(t)$ = the profit of power generation [billion yen]

$C_T(t)$ = the total cost of power generation [billion yen]

Finally, the present values of the profit are obtained by discounting the profit at the long-term discounting rate. Because there is no cash flow until 2006, the focus of the DCF analysis is on 20 years from 2006 to 2025 (t=8~27):

$$PV(G) = \sum_{T=1}^{20} \frac{G(t)}{(1+r)^T}$$
$$T = t - 7$$

where

PV(G) = the present value of the profit [billion yen]

r = the long-term discount rate [-]

Expected Mean Values of CO2 Emission

The expected mean value of CO2 emissions depends on the quantity and the CO2 intensity of make-up electricity the model calculates. The cumulative CO2 emissions are calculated from 2012 to 2025 (t=14~27) because CO2 emission are controlled from:

$$E(W) = \sum_{t=14}^{27} E(w(t))$$

$$E(w(t)) = \sum_{n=0}^{6} \frac{\eta \cdot Q_M(n,t) \cdot P(n,t)}{1000000}$$

where

E(W) = the expected mean value of cumulative CO2 emission [million t-C]

E(w(t)) = the expected mean value of CO2 emission in the year "*t*" [million t-C]

η = the CO2 intensity of make-up electricity [g-C/kWh]

Long-term Contract

Under a long-term contract, we assume that the utilities build new energy plants in the years 2009, 2010, and 2011. This is because, once the utilities hold a long-term contract, the plants commissioned later can not supply electricity. Therefore, the utilities build new energy power plants before they execute a long-term contract. For instance, when the utilities build three new energy projects, the first project will commission a plant in the year 2009, the second in 2010, and the third in 2011 so that the utilities can build new energy power plants from three projects without any conflict with a long-term contract:

$$Q_E(t)=0,\ (M=0)\quad \underset{(M=1)}{\begin{cases}0\\0\\0\\17{,}340\end{cases}}\quad \underset{(M=2)}{\begin{cases}0\\0\\17{,}340\\17{,}340\times 2\end{cases}}\quad \underset{(M=3)}{\begin{cases}0 & t=0\sim 10\,(1998\sim 2008)\\17{,}340 & t=11\quad (2009)\\17{,}340\times 2 & t=12\quad (2010)\\17{,}340\times 3 & t=13\sim\quad (2011\sim\quad)\end{cases}}$$

The output of nuclear power projects depends on the history of plant development as well as the number of commissioned projects. Therefore, with the aid of an event tree, the DCF analysis calculates the possible phases of plant development and their probabilities. Then, it calculates the expected mean value of make-up electricity and the output of nuclear projects. An appendix shows the phases of possible plant development and the calculation of their probabilities. We obtain the expected cost of make-up electricity by multiplying the quantity of make-up electricity by the probabilities:

$$E\left(\hat{C}_M(t)\right)=\sum_{m=0}^{6}\hat{C}_M(m,t)\cdot P_M(m,t)$$

$$\hat{C}_M(m,t)=\frac{c_M\times\hat{Q}_M(m,t)}{1000}$$

$$\hat{Q}_M(m,t)=17{,}340\times m$$

where

$E\left(\hat{C}_M(t)\right)$ = the expected mean value of the cost of make-up electricity [billion yen]

$\hat{C}_M(m,t)$ = the cost of make-up electricity when "***m***" long-term contracts are held [billion yen]

$P_M(m,t)$ = the probability of "***m***" long-term contracts being held [-]

$\hat{Q}_M(m,t)$ = the quantity of make-up electricity when "***m***" long-term contract are held [GWh]

$$E\left(\hat{C}_N(t)\right)=\sum_{m=0}^{6}\hat{C}_N(m,t)\cdot P_M(m,t)$$

$$\hat{C}_N(m,t)=\frac{c_N\times\hat{Q}_N(m,t)}{1000}$$

$$\hat{Q}_N(m,t) = D(t) - Q_E(t) - \hat{Q}_M(m,t)$$

where

$E\left(\hat{C}_N(t)\right)$ = the expected mean value of the cost of nuclear power generation [billion yen]

$\hat{C}_N(m,t)$ = the cost of nuclear power generation when "*m*" long-term contracts are held [billion yen]

$\hat{Q}_N(m,t)$ = the output of nuclear power projects when "*m*" long-term contract are held [GWh]

The other calculations of a long-term contract are the same as those of a short-term contract. Table 4-6 shows parameters of the DCF analysis.

Table 4-6 Parameters of the Cost Model

	Costs of Power Generation	
	[yen/kWh]	[cent/kWh]*
Rate of Electricity	18.81	15.01
New Energies	15 ~ 30	12 ~ 25
Nuclear	10.12	8.43
Make-up	14.00	11.67
T&D	1.46	1.22
Penalty	0 ~ 6**	0 ~ 5
	(0 ~ 30,000 [yen/t-C])	(0 ~ 250 [$/t-C])
Discount Rate	7.2[%]	

* Exchange Rate = 120[yen/$]

** CO2 Intensity of Make-up = 200[g-C/kWh]

Analyzing Uncertainty

The DCF analysis depends on certain assumptions. To analyze the influence of these assumptions, the model examines three scenarios of nuclear power plant development and the sensitivities of the costs of new energy power generation and the penalty of emitting CO2. In addition, the DCF analysis estimates the approximate range of possible profit. Table 4-7 summarizes a framework for the analysis

Table 4-7 Framework of the Analysis

Contract to Purchase Make-up Electricity				
Short-term Contract		Long-Term Contract		
Strategy for Reducing Risk	**Scenarios**	**Sensitivity Analysis**		**Results**
(N, M)	Nuclear Power Plant Development	Cost of New Energies	Penalty of Emitting CO2	
				System Probability of CO2 Control
(6, 0)	Optimistic	higher	higher	Expected CO2 emission
(6, 1)				
(6, 2)	Moderate			Present Value of Expected Profit
(6, 3)				
	Pessimistic	lower	lower	Approximated Standard Deviation Interquartile Range
M	μ	c_E	c_P	$P, W, G, \sigma, G_{25\%}, G_{75\%}$
Exogenous Inputs				Endogenous Outputs

Scenario Analysis of Nuclear Power Plant Development

There are divided views on nuclear power plant development. The MITI expects that 20 nuclear power plants will be commissioned by 2010, while an expert from the utilities states that 11 of 20 plants is the best they can do. In other words, the utilities anticipate that 5 of 6 projects will not be completed by 2011 while the MITI expects that all 6 projects will be completed by then. Because there is no consensus on the future of nuclear power plant development, it is difficult to make an assumption about the probability of plant development.

For this reason, the DCF analysis examines three scenarios of nuclear power plant development; optimistic, moderate, and pessimistic scenario. The optimistic scenario assumes that 5 of 6 projects will be completed by 2011. Consequently, the expected mean value of completed projects is 5.0. The expected mean value of the moderate and pessimistic scenarios is 3.5 and 2.0 respectively.

Table 4-8 summarizes the assumptions of these three scenarios. To simplify, we will assume that all scenarios have the same relative error, which is the ratio of standard deviation to mean, and that the relative error is equal to that of the distribution of the partial lead-time discussed in Section 4.2. For instance, the moderate scenario expects that 3.5 projects will be completed or 6.4 plants will be commissioned. Because it assumes that 9 other plants are commissioned without delay, a total of 15.4 plants should be commissioned. Because these three scenarios have the same relative error, the mean and the dispersion of the lead-time of the pessimistic scenario is larger than that of the optimistic scenario.

The average rate for commissioning nuclear power plants is 1.82 plants per year for the optimistic scenario, 1.54 plants per year for the moderate scenario, and 1.27 plants per year for the pessimistic scenario. As discussed in Section 4.3, the past average is 1.65 plants per year. The rate of the optimistic scenario is higher than that of the past average by 10%, while those of the moderate and pessimistic scenarios are smaller by 7% and 23% respectively.

The probability of a project being completed by 2011 are 0.83 in the optimistic scenario, 0.58 in the moderate scenario, and 0.33 in the pessimistic scenario. The system probability of 6 projects being completed is 0.33 in the optimistic scenario, 0.04 in the moderate scenario, less than 0.01 in the pessimistic scenario.

Table 4-8 Scenarios of Nuclear Power Plant Development

	Expected Mean Value			Distribution of the Lead Time			
	Projects*	Plants**	F_{2011}	t[year]	μ	σ	σ/μ
Optimistic	5.0	18.2	0.83	9.74	2.28	0.30	0.13
Moderate	3.5	15.4	0.58	12.13	2.50	0.33	0.13
Pessimistic	2.0	12.7	0.33	15.16	2.72	0.36	0.13

* The utilities launches 6 projects.

** The utilities plan to build 20 plants and 9 of them are assumed to be build.

Sensitivity Analysis of Penalty and Cost of New Energy Power Generation

The costs of new energy power generation are also subject to uncertainty because they can decrease in the future due to technology innovations, economies of scale, learning effects, and market competition. The penalty for emitting CO2 is decided by a regulatory agency. Opinion is divided on the appropriate penalty.

To evaluate the influence of these parameters, the DCF analysis examines the sensitivity of them in relation to the profit. The cost of new energy power generation varies from 15 yen per kWh to 30 yen per kWh. They are roughly 1.5 times and 3.0 times higher than that of nuclear power generation.

To determine the penalty for CO2 emissions, the Environmental Agency of Japan (EAJ) issued the analysis of carbon tax (EAJ, 1997b). The EAJ examines carbon tax raging from 3,000 yen per t-C to 30,000 yen per t-C (25 [$/t-C] ~ 250 [$/t-C]). While there are a number of studies about carbon tax, the carbon tax used to stabilize CO2 emissions in Japan is generally higher than that of the US. This is because the marginal cost of CO2 reduction in Japan is higher than that of the US. For instance, the Electric Research Center of Japan estimates that the necessary tax level should amount to 4,000 yen per t-C (33[$/t-C]) in 1990 and rise to 64,000 yen per t-C (533[$/t-C]) by 4000 yen every year until 2005 (Yamaji, 1990). The estimates of other studies range roughly from 17,000 yen per t-C to 63,000 yen per t-C (140 [$/t-C]) ~ 525 [$/t-C]) (EAJ, 1997c).

The influence of the penalty also depends on the CO2 intensity of make-up electricity. As discussed in Chapter 3, CO2 intensity depends on the type of fuel used and the thermal efficiency of power generation. For simplicity, the model assumes that make-up electricity has the CO2 intensity of 200 g-C per kWh, which is higher than that that of LNG-burning power plants and lower than that of coal-burning power plants. In that case, the effect of the penalty on power generation costs is roughly 0.6 yen per kWh ~ 6 yen per kWh (0.5 [cent/kWh] ~ 5 [cent/kWh]).

Evaluating the Range of Possible Profit

Though the average lead-time is assumed in these three scenarios, the actual lead-time can fluctuate. Thus, the expected profit may also fluctuate around the expected mean value. To estimate the range of possible profit, the DCF analysis evaluates the standard deviation of the profit, assuming *Gaussian* approximation. With a Gaussion distribution, the variance of expected profit is approximately (Morgan, 1990):

$$\sigma_G^2 \approx \left[\frac{\partial G}{\partial \mu}\right]_{\mu^0} \cdot \sigma_\mu^2$$

where

σ_G = the standard deviation of the expected profit "***G***"

σ_μ = the standard deviation of logarithms of the lead time "μ"

The partial derivative is estimated as the ratio of the change in profit to the change in lead-time:

$$\left[\frac{\partial G}{\partial \mu}\right]_{\mu^0} \approx \frac{G(\mu^0 + \Delta\mu) - G(\mu^0)}{\Delta\mu}$$

Assuming approximate standard deviation, the DCF analysis evaluates the interquartile range of expected profit, which is the rage between the lower 25% and the upper 75% of profit. The profit between them has a probability of 0.5.

4.6 RESULTS AND DISCUSSION

Figure 4-7 and Figure 4-8 show the examples of the DCF analysis of a short-term and a long-term contract respectively. A sold line denotes the demand of electricity analyzed in the DCF. Square points denote the expected output of 6 nuclear power projects, while solid ones denote that of 6 nuclear power projects and 2 additional new energy power projects. Consequently, the difference between the demand and the output represents the quantity of make-up electricity. Bar charts represents the present values of expected annual profits.

For a short-term contract, the total output continuously increases until 2025 because the utilities may cancel the held contracts when additional nuclear power plants are commissioned. For a long-term contract, however, the total output does not increase after 2011 because the utilities must purchase make-up electricity once the utilities agree to a long-term contract. In the moderate scenario, for instance, make-up electricity reaches almost half of the demand when the utilities launch no new energy projects.

In reality, the results may fall in the middle because the utilities can substitute their thermal power projects for nuclear power projects. When a nuclear power project is behind schedule, the utilities move up their thermal power project instead of purchasing electricity to make up the deficit capacity. This rearrangement of power plant development schedules has the same effect as a short-term contract. When they move up thermal power plant projects, the utilities can commission nuclear power plants later.

Actual contracts with independent power producers are long-term ones. After the amendment to the Electricity Utility Industry Law in 1995, the utilities have held contracts to purchase electricity with independent power producers. The contracts are fifteen-year contacts. There are neither one-year nor short-term contracts held.

For these reasons, the actual outcome is falls between that of a one-year contract and that of a long-term contract. A one-year contract and a long-term contract are the extreme cases that most clearly demonstrate the influence of the delay of nuclear power plant development.

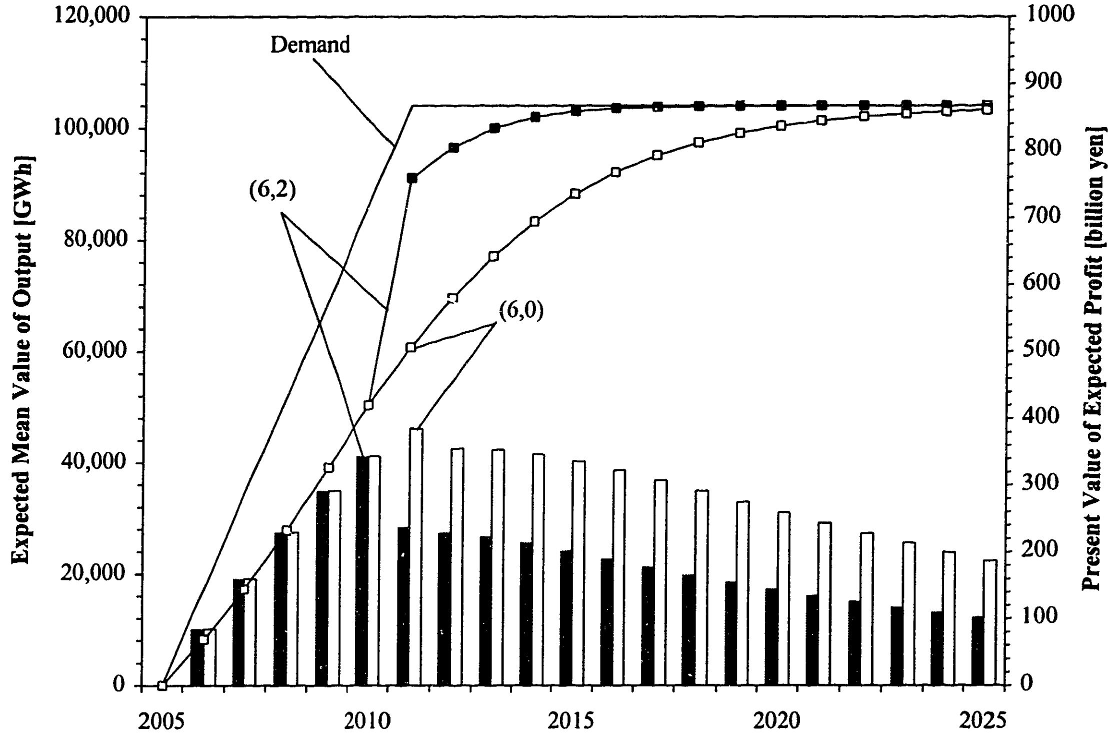


Figure 4-7 Example of Short-term Contract (Moderate, c_P=6,000[yen/t-C], c_E=20[yen/kWh])

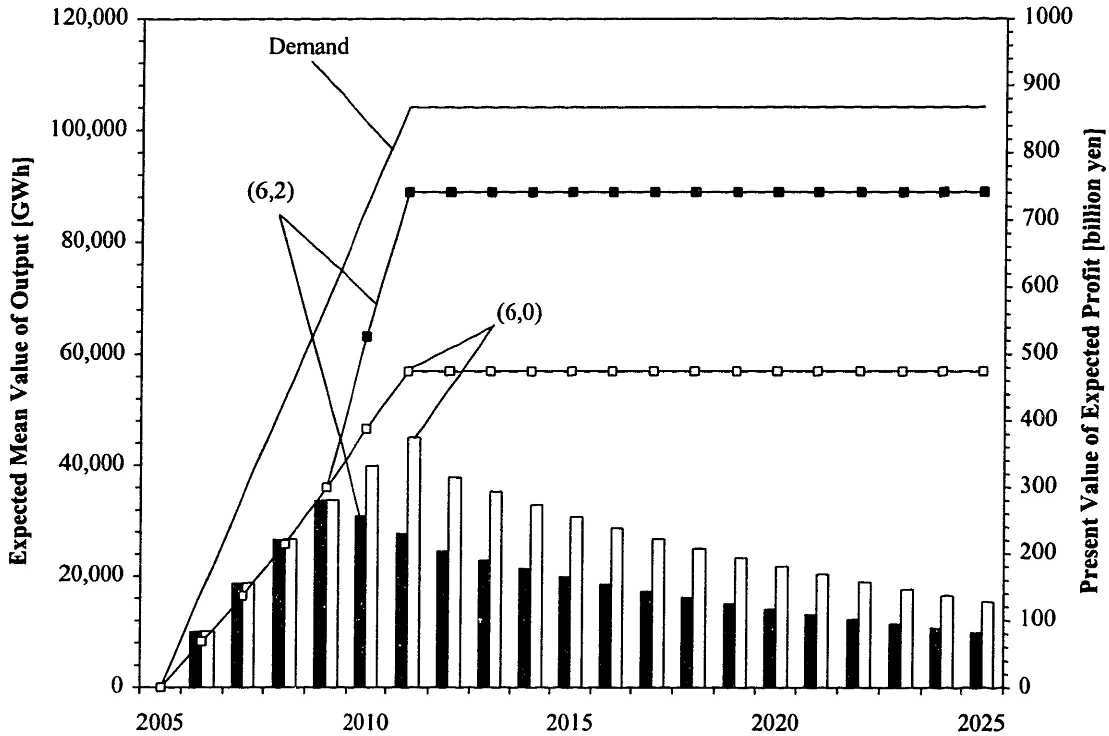


Figure 4-8 Example of Long-term Contract (Moderate, c_P=6,000[yen/t-C], c_E=20[yen/kWh])

System Probabilities of CO2 Control and Expected CO2 Emissions

Figure 4-9 shows system probabilities, which are defined as "6 projects that are completed not later than 2011." The effect of new energy power projects is an S shape. When system probabilities are low, new energy projects have little effect on the enhancement of system probabilities. For instance, new energy projects have virtually no meaningful effect on system probabilities in the moderate and pessimistic scenarios of a long-term contract.

By contrast, new energy projects have the most significant effect on medium system probabilities. For instance, adding a new energy project enhances a system probability from 0.33 to 0.74 in the optimistic scenario of a short-term contract. The effect of new energy projects, however, diminishes progressively with the increase of system probabilities. The third added project increases the system probability from 0.94 to 0.99.

Generally, the effects on system probabilities of a short-term contract are more significant than for a long-term contract. This is because it is only when the utilities complete all projects on schedule that all nuclear power plants are brought on-line under a long-term contract. By contrast, under a short-term contract, the utilities can bring all nuclear power plants on-line as long as they complete six projects not later than 2011.

Figure 4-10 shows the expected mean values of CO2 emissions. Generally, the effect of new energy projects on CO2 emissions is progressive. Consequently, while the effect on system probabilities of a long-term contract is smaller than those of a short-term contract, the effects on CO2 emissions of a long-term contract is greater than those of a short-term contract. In the moderate scenario, adding three new energy projects enhances system probabilities from 0.04 to 0.76 under a short-term contract, and from 0.02 to 0.14 under a long-term contract. But it decreases CO2 emissions by 35 million t-C of the former, by 118 million t-C of the latter.

The effect on CO2 emissions is most significant in a pessimistic scenario of a long-term contract. In that case, 4 of 6 nuclear power projects are not completed by 2022 and CO2 emissions are 200 million t-C without new energy projects. Launching three new energy projects decreases it to 58 million t-C by 142 million t-C. When the utilities commission no nuclear power plants, CO2 emissions reach 291 million t-C. The reduction of 142 million t-C accounts for half of it.

In conclusion, new energy projects enhance most effectively the system probabilities of a high-probability situation, such as optimistic scenarios or a short-term contract. In contrast, they decrease most drastically with CO2 emissions of a high-emission situation, such as pessimistic scenarios or a long-term contract.

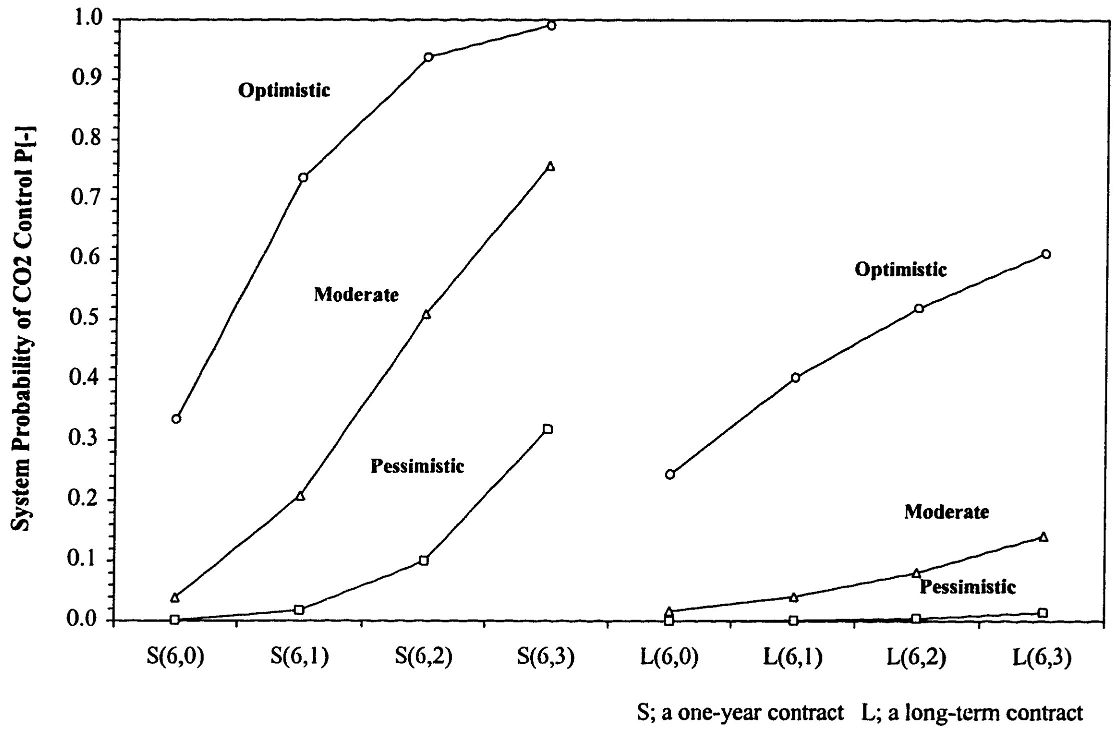


Figure 4-9 System Probability of CO2 Control

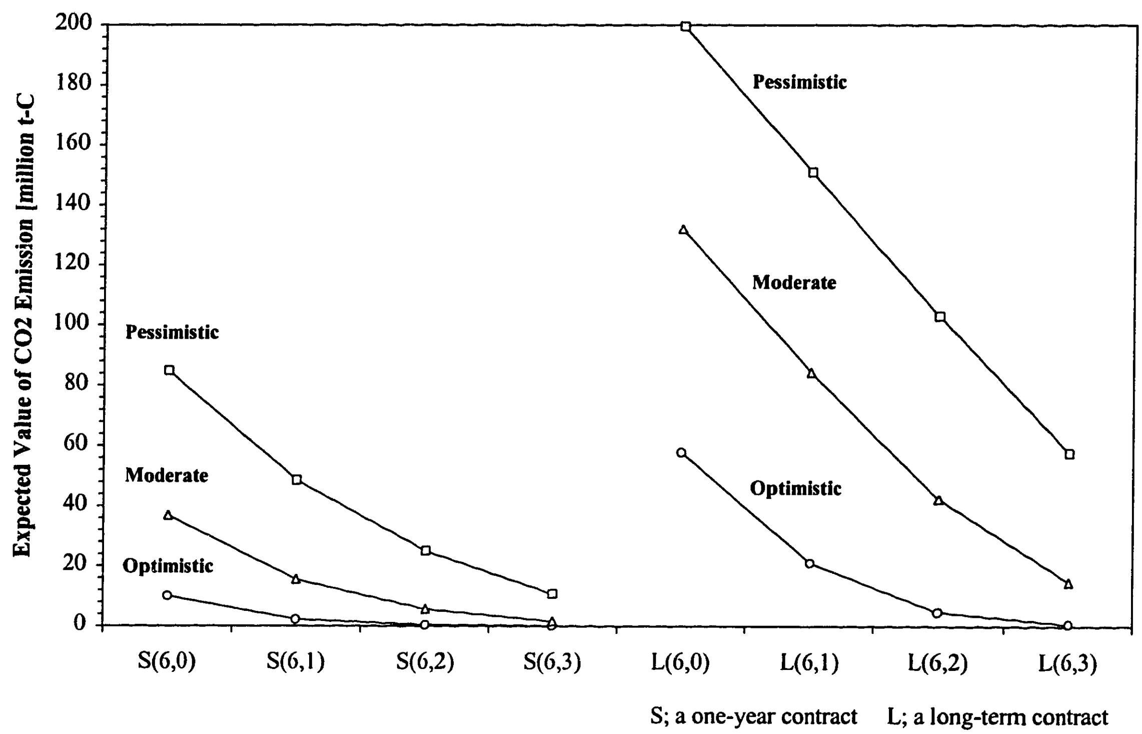


Figure 4-10 Expected Mean Value of CO2 Emission

Trade-off between CO2 Control and Profit

Figure 4-11 ~ Figure 4-18 shows the trade-off between profits and system probabilities of CO2 emissions control or profits and CO2 emissions. Figure 4-11 ~ Figure 4-14 shows the results of a short-term contract while Figure 4-15 ~ Figure 4-18 shows the results of a long-term contract. The cost of new energy power generation is 15 [yen/kWh] for Figure 4-11, Figure 4-13, Figure 4-15, and Figure 4-17, 20 [yen/kWh] for Figure 4-12, Figure 4-14, Figure 4-16, and Figure 4-18.

The source of the trade-off is the gap in cost between nuclear power projects and new energy power projects. While the cost of new energy power projects is definite, that of nuclear power projects depends on the probability of nuclear power projects being completed. When the utilities complete all nuclear power projects on schedule, the cost of new nuclear power project is equal to that of nuclear power generation. When nuclear power projects are behind schedule, the utilities purchase make-up electricity and pay the penalty for CO2 emissions. In that case, the cost of delay in plant development is written as:

Cost of Delay = (Cost of Make-up + Penalty of Emitting CO2) × Probability of Delay

When the probability of delay is small, the trade-off depends on the gap in cost between nuclear power generation and new energy power generation; 10 yen per kWh and 15 ~ 30 yen per kWh. In contrast, when the probability is high, the trade-off depends on the gap in cost between new energy power generation and delay. For instance, when the cost of make-up electricity is 14 yen per kWh and the penalty for CO_2 emissions is 6,000 yen per t-C or 1.2 yen per kWh (50 [$/t-C] or 1 [cent/kWh]), the cost of delay is 15.2 yen per kWh (12.7 [cent/kWh]). Because the probability of delay is less than 1, the expected mean value of the cost is less than 15.2 yen per kWh. In that case, when the cost of new energy is 15 yen per kWh (12.5 [yen/kWh]), the trade-off is virtually negligible because the gap between cost of new energy power generation and delay is negligible. By contrast, when the cost of new energy is 20 yen per kWh (16.7 [cent/kWh]), the trade-off is clear over all probabilities. This is because the cost of 20 yen per kWh is higher than both the cost of delay and the cost of nuclear power generation.

A short-term contract and a long-term contract have the basically same trade-off. But the effect of new energy projects is more significant for system probabilities of a short-contract than those of a long-term contract. Therefore, the marginal costs of enhancing system probabilities of a short-term contract are smaller than that of a long-term contract. For instance, when the cost of new energy power generation is 20 yen per kWh in the moderate scenario, a new energy project enhances system probabilities to 0.17 under a short contract and to 0.02 under a long-contract. At the same time, it reduces the profit by 818 billion yen of the former and by 552 billion yen of the latter. Consequently, the marginal costs of enhancing a system probability are 4,812 billion yen for a short-term contract, and 27,600 billion yen for a long-term contract.

Similarly, the marginal costs of reducing CO2 emissions in a long-term contract are smaller than that of a short-term contract because CO2 emissions of the former are reduced further than that of the latter. In the preceding example, three new energy projects reduce CO2 emissions by 48 million t-C under a long-term contract, and by 21 million t-C under a short-term contract. The marginal costs of reducing CO2 emissions are 12,000 yen per t-C (100 [$/t-C]) for the former and 38,000 yen per t-C (317 [$/t-C]) for the latter.

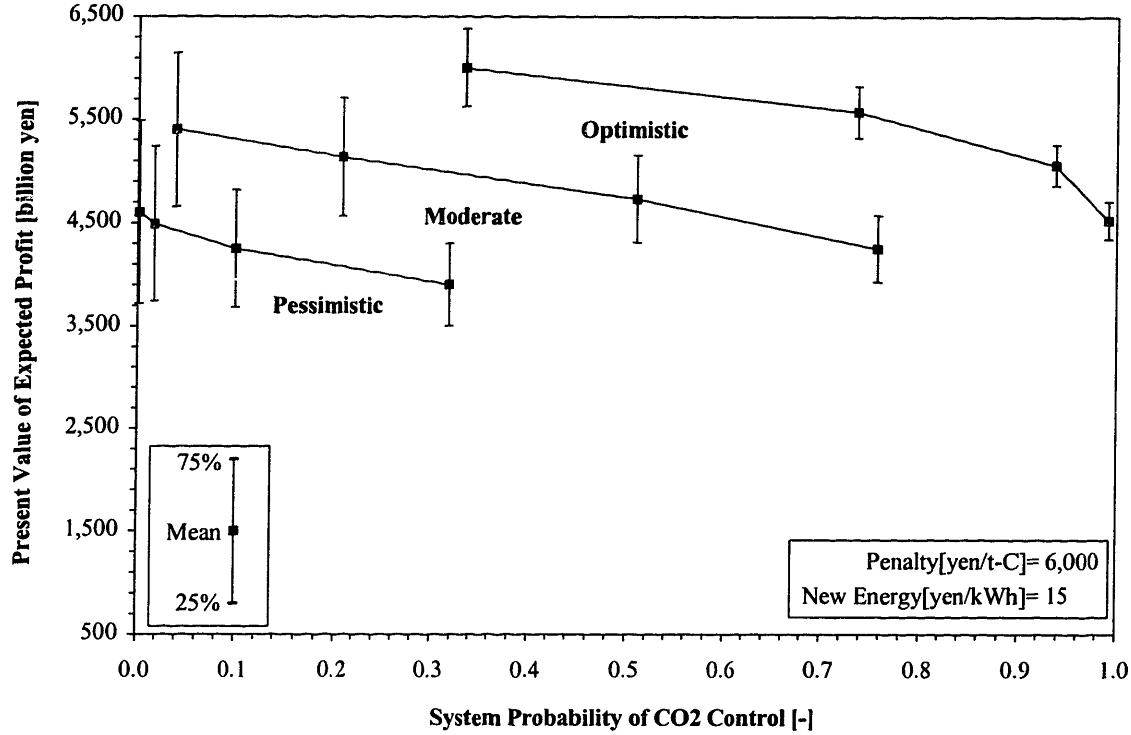


Figure 4-11 Trade-off between Profits and System Probabilities of CO2 Control(Short-term, Low-cost)

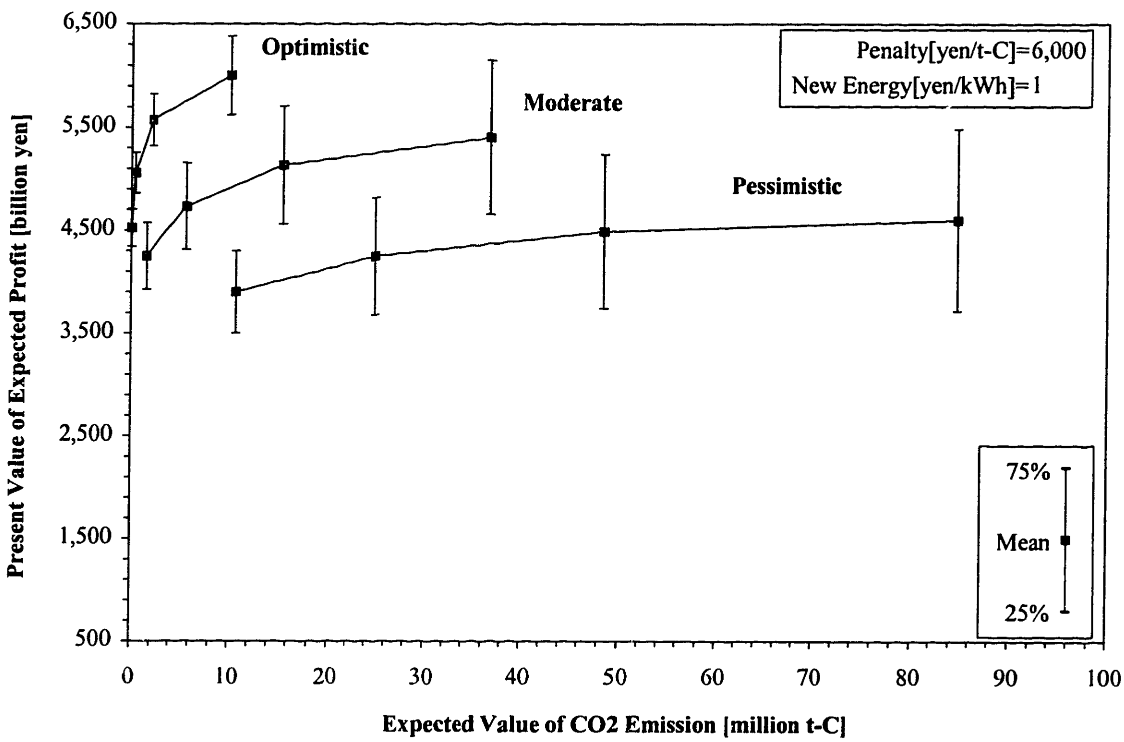


Figure 4-12 Trade-off between Profits and CO2 emissions (Short-term, Low-cost)

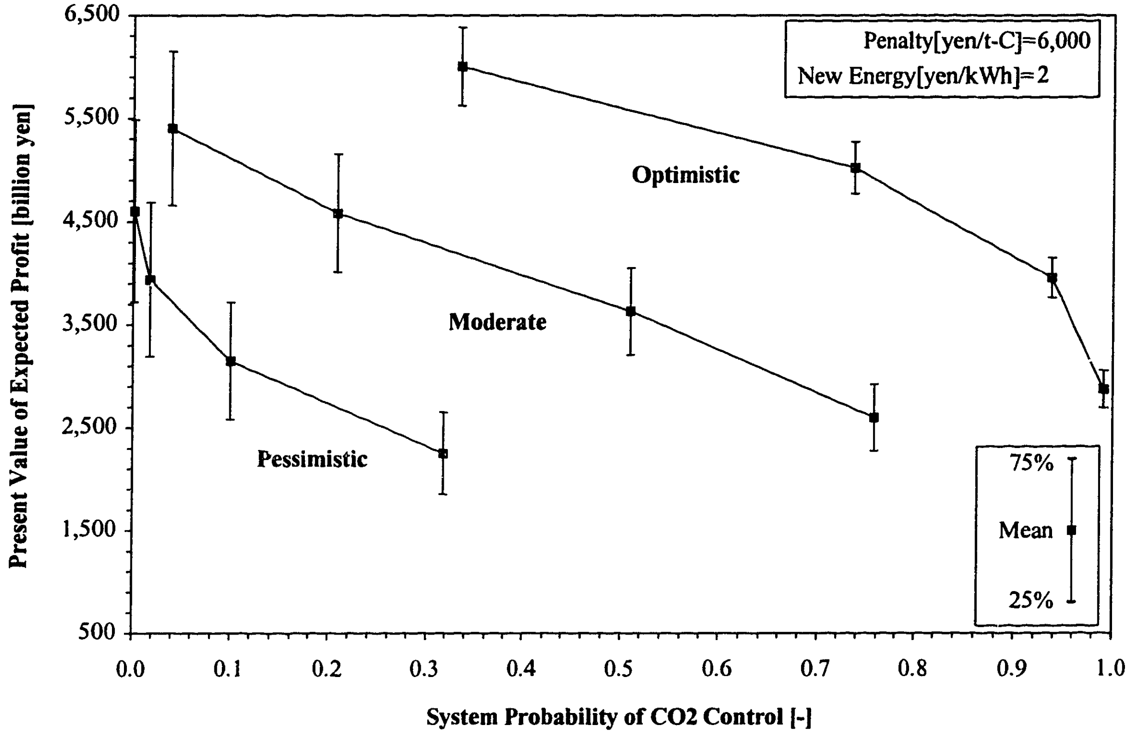


Figure 4-13 Trade-off between Profits and System Probabilities of CO2 control (Short-term, High-cost)

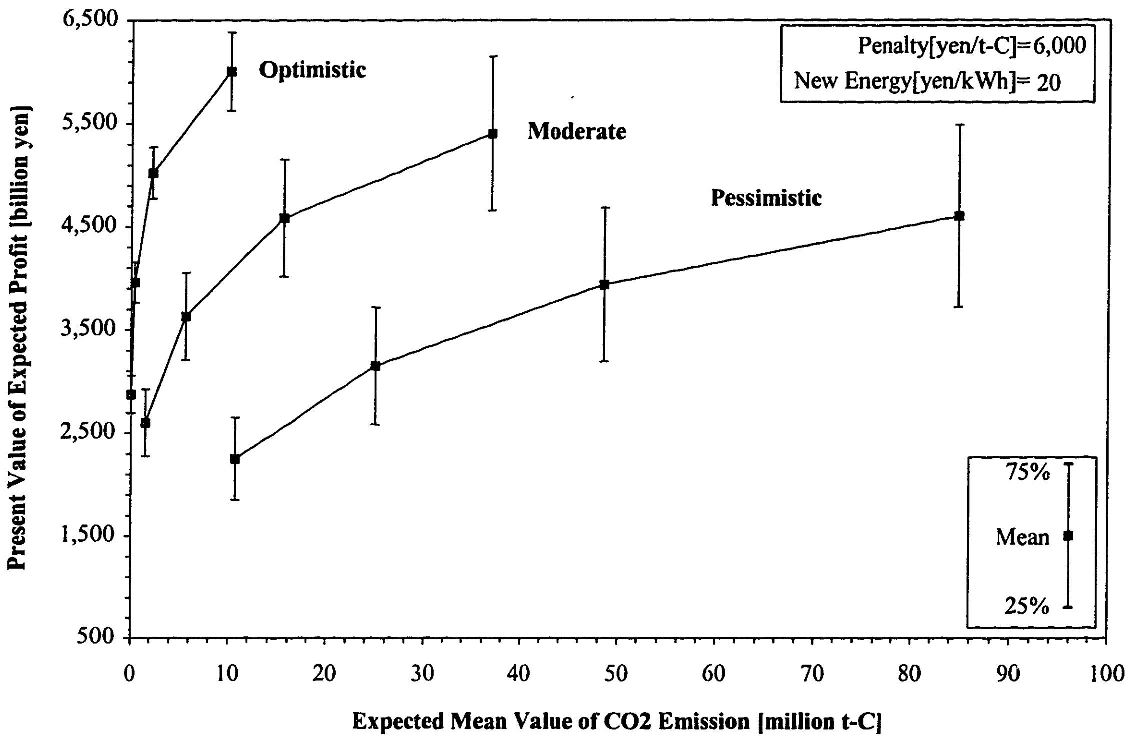


Figure 4-14 Trade-off between Profits and CO2 emissions (Short-term, High cost)

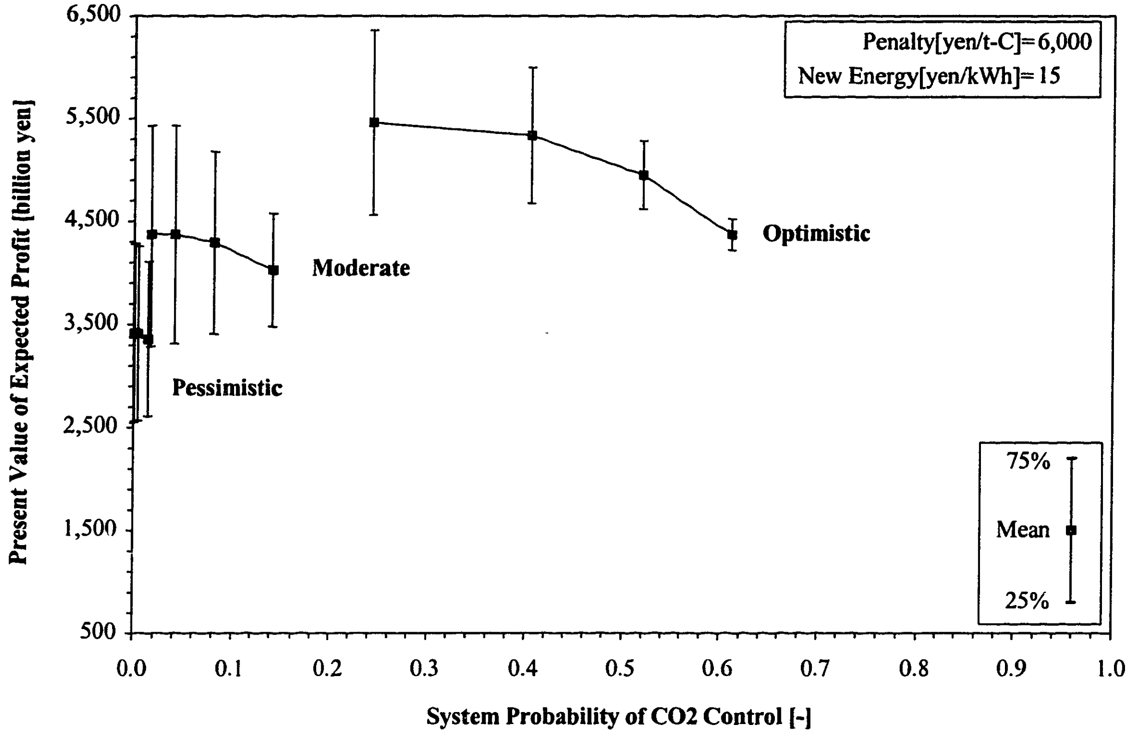


Figure 4-15 Trade-off between Profits and System Probabilities of CO2 Control(Long-term, Low cost)

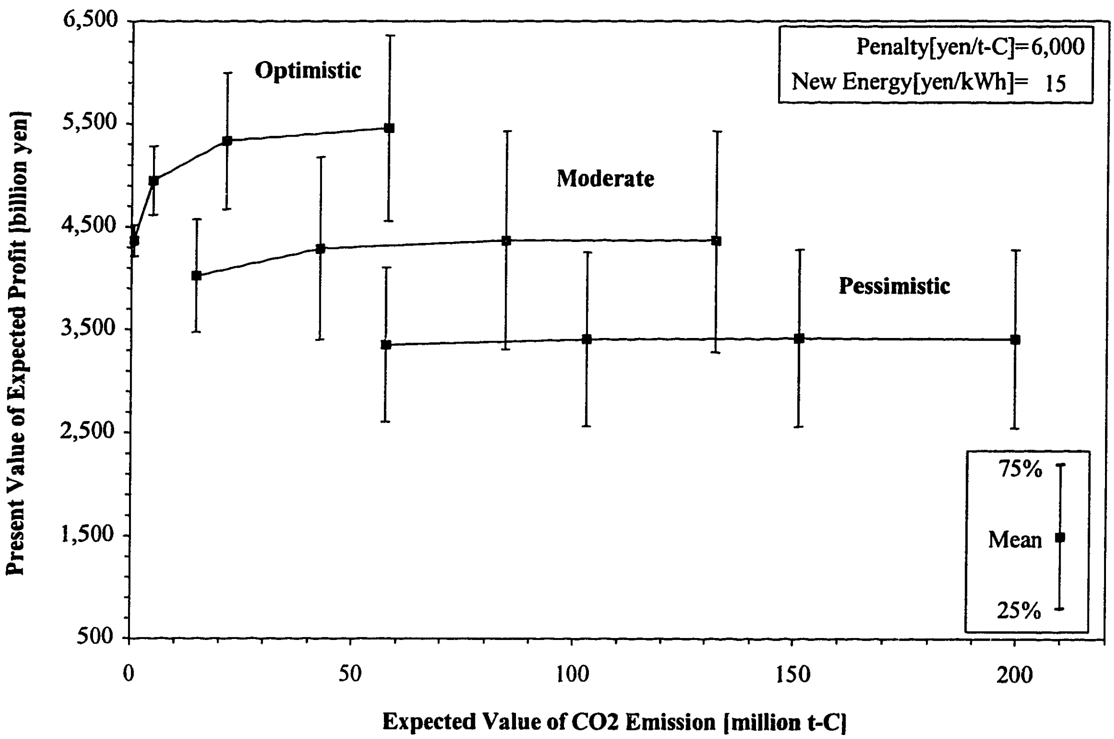


Figure 4-16 Trade-off between Profits and CO2 emissions (Long-term, Low-cost)

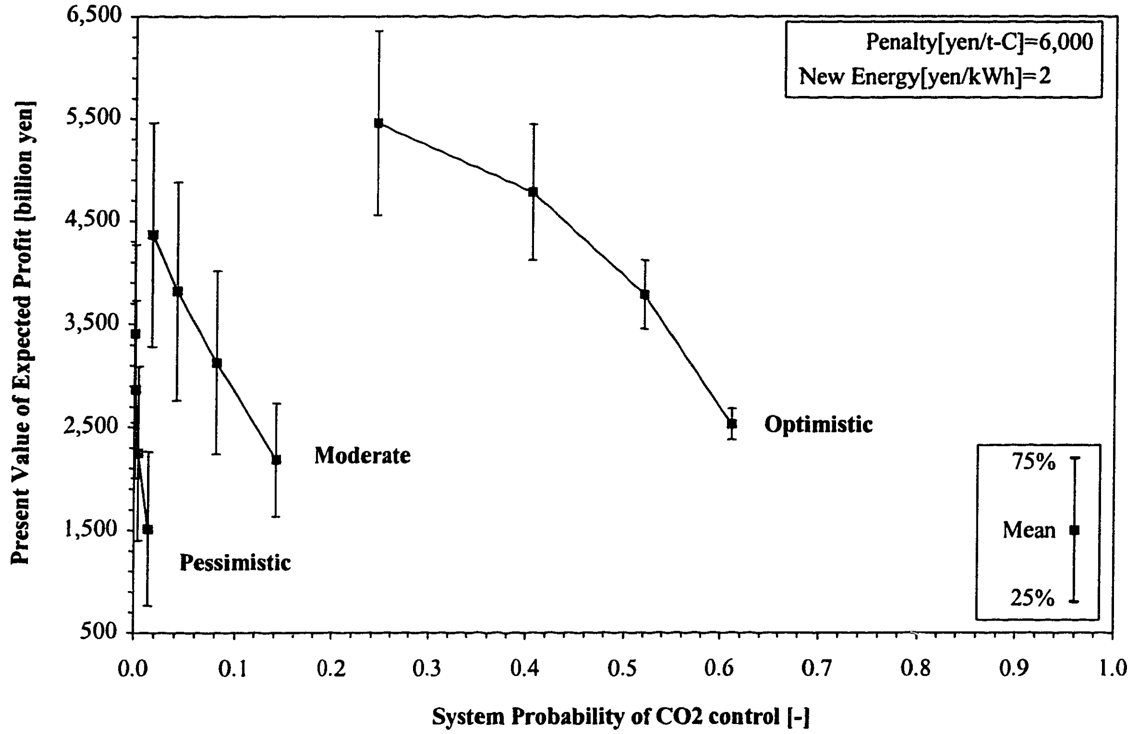


Figure 4-17 Trade-off between Profits and System Probabilities of CO2 Control(Long-term, High-cost)

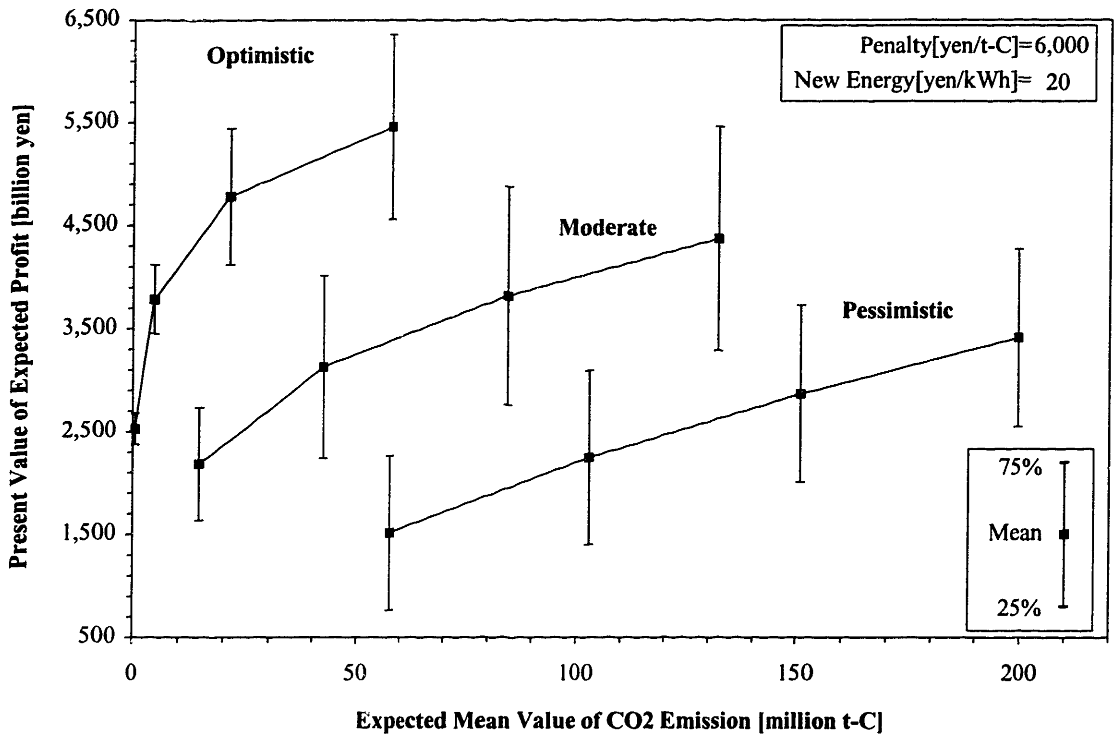


Figure 4-18 Trade-off between Profits and CO2 emissions (Long-term, High-cost)

Sensitivity Analysis

Figure 4-19 ~ Figure 4-22 shows the sensitivity analysis of the cost of new energy power generation and the penalty for CO2 emissions. For comparability, the sensitivities of the penalty are translated into the penalty per unit electricity. That is, when CO2 intensity of make-up electricity is 200 g-C per kWh, the penalty of 5,000 yen per t-C is equivalent to 1 yen per kWh (the penalty of 42 dollars per t-C is equivalent to 0.8 cents per kWh).

The sensitivity can be defined by the partial derivatives of profit with the cost and the penalty. Because the partial derivatives are constant, the sensitivities are linear. Table 4-9 and Table 4-10 summarize the sensitivities in terms of kilowatt-hour equivalents. For the cost, the sensitivity is proportional to the quantity of new energy output. Because the output of new energy projects is definite irrespective of contracts, the sensitivity under a short-term contract is the same as that under a long-term contract. New energy power plants, however, are commissioned at once in 2011 under a short-term contract, and one at a time from 2009 to 2011 under a long-term contract. For this reason, discounting the output causes the small differences in the sensitivities between a short-term contract and a long-term contract.

For the penalty, the sensitivity is proportional to the expected mean value of make-up electricity purchased beginning in the year 2012. Under a short-term contract, the utilities cancel contracts to purchase make-up electricity when they commission nuclear power plants. In contrast, under a long-term contract, the utilities must continuously purchase make-up electricity once they hold contracts. Therefore, the make-up electricity of the former is smaller than that of the latter and the penalty of the former is more sensitive to profits than that of the latter. Similarly, the make-up electricity of pessimistic scenarios is greater than that of optimistic scenarios. The penalty of pessimistic scenarios is more sensitive to profit than that of optimistic scenarios.

When the utilities purchase roughly the same amount of make-up electricity as that of new energy output, the penalty is as sensitive as the cost of new energy power generation in terms of a unit kilowatt-hour equivalent. Practically speaking, however, the penalty has a limited effect on profit. For instance, the gap in cost between new energy power generation and nuclear power generation is some 5 yen per kWh or more. It is equivalent to the penalty of 25,000 yen per t-C (4.2 cents per kWh is equivalent to 208 dollars per t-C). Therefore, unless a considerably high penalty is imposed on CO2 emissions, nuclear power dose not impair cost-competitiveness. The moderate penalty, however, still has a meaningful effect on fuel switching because the gap in cost between coal, oil and LNG power generation is about 1 yen per kWh.

In summary, profits are sensitive to the cost of new energy power generation and insensitive to the penalty. The moderate penalty has a meaningful effect on fuel switching but not on the introduction of new energy power generation. For this reasons, it is also possible that moderate subsidy has little effect on it. This is because the gap in cost between nuclear power generation and new energy power generation is greater than the cost of delay

Table 4-9 Sensitivities of Cost of New Energy and Penalty (Short-term)

		Sencitivity [billion yen/(yen/kWh)]			
		(6,0)	(6,1)	(6,2)	(6,3)
	Optimistic	-18	-3	-0.4	-0.03
Penalty*	Moderate	-73	-28	-9	-2
	Pessimistic	-174	-99	-49	-19
Cost of New Energy		0	-110	-220	-331

* Penalty; 1[yen/kWh]=5,000[yen/t-C] (42[$/t-C])

Table 4-10 Sensitivities of Cost of New Energy and Penalty (Long-term)

		Sencitivity [billion yen/(yen/kWh)]			
		(6,0)	(6,1)	(6,2)	(6,3)
	Optimistic	-118	-43	-10	-1
Penalty*	Moderate	-269	-172	-86	-30
	Pessimistic	-406	-307	-209	-117
Cost of New Energy		0	-110	-233	-368

* Penalty; 1[yen/kWh]=5,000[yen/t-C] (42[$/t-C])

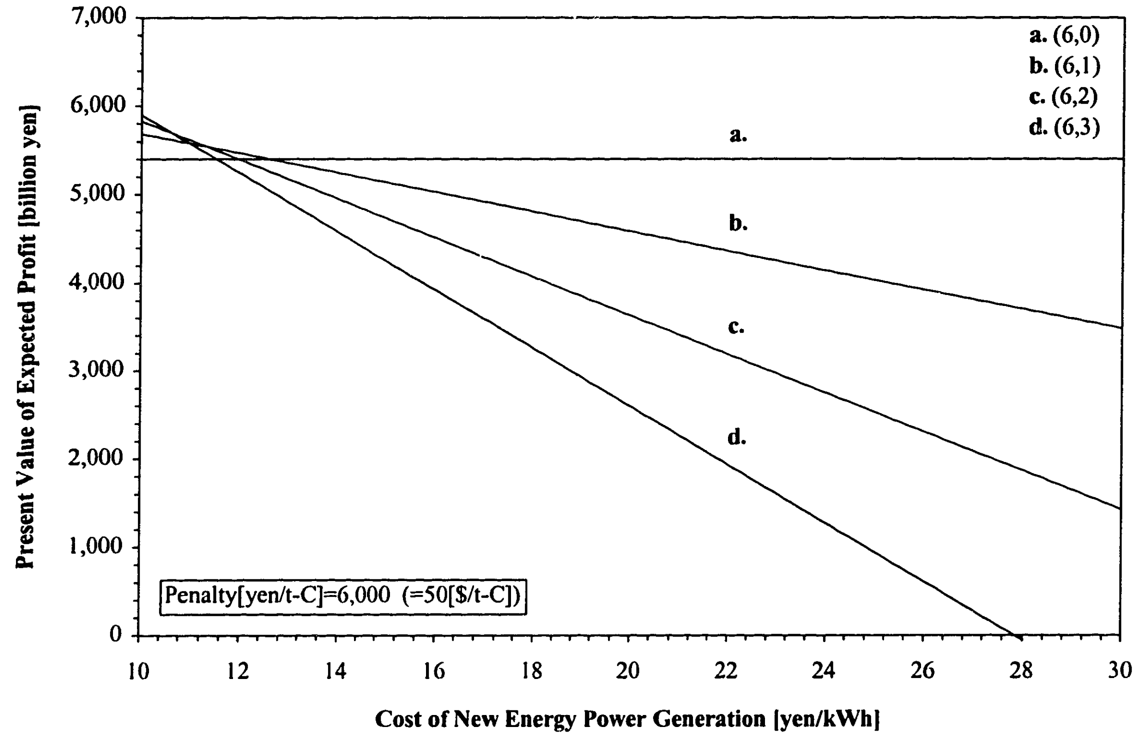


Figure 4-19 Sensitivity Analysis of New Energy Power Generation Cost (Short-term contract)

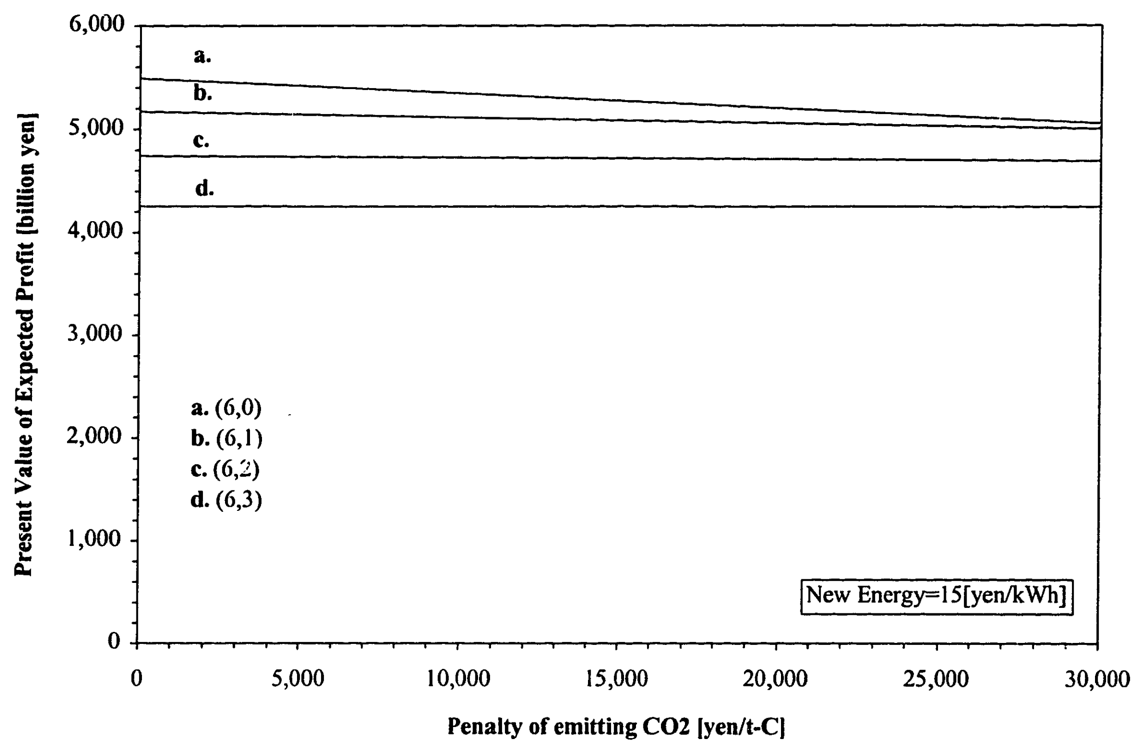


Figure 4-20 Sensitivity Analysis of Penalty of Emitting CO2 (Short-term contract)

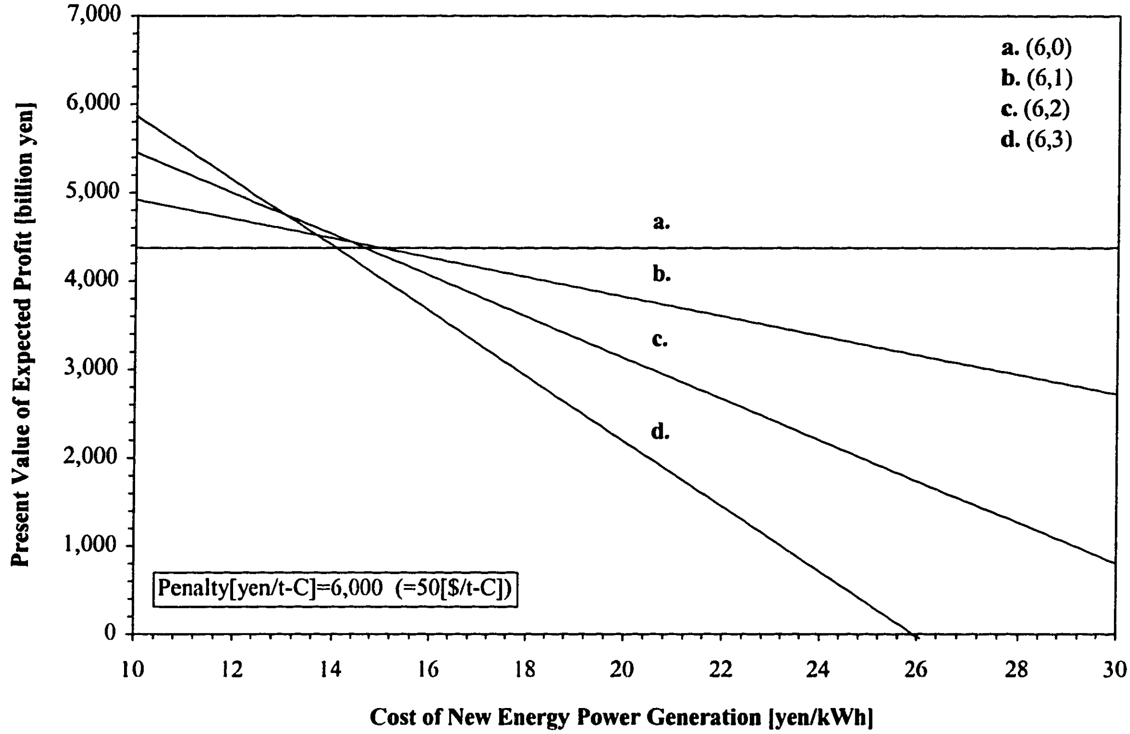


Figure 4-21 Sensitivity Analysis of New Energy Power Generation Cost (Long-term contract)

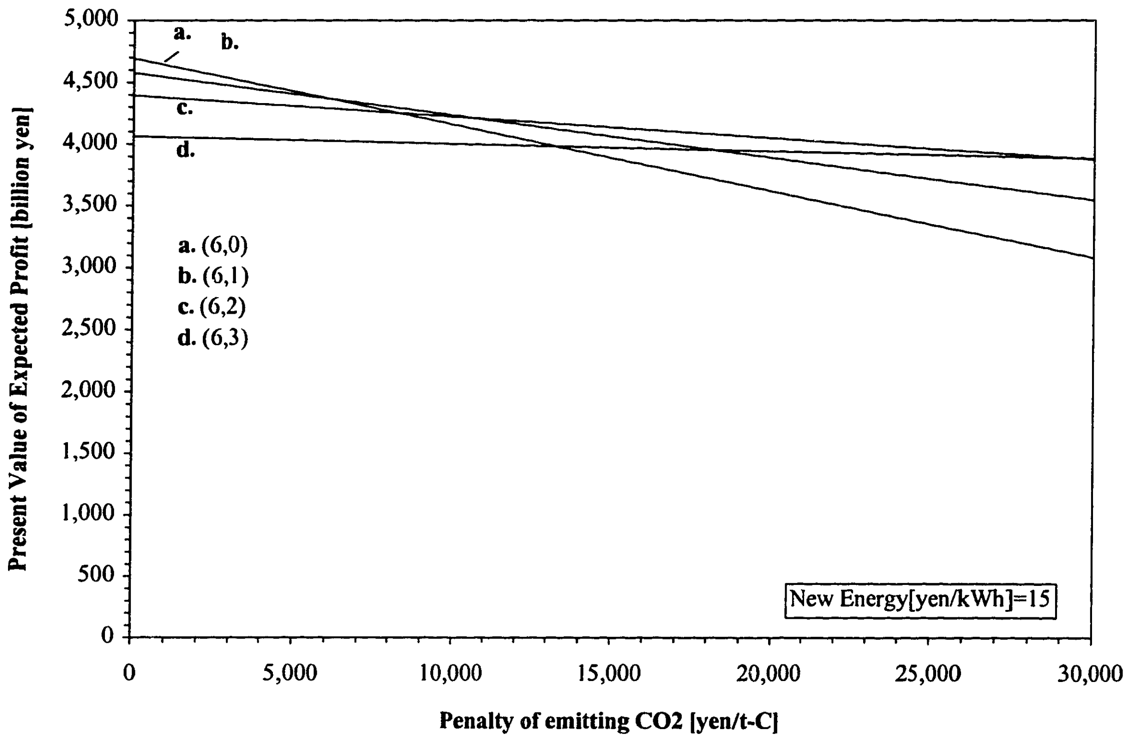


Figure 4-22 Sensitivity Analysis of Penalty of Emitting CO2 (Long-term contract)

4.7 SUMMARY

This chapter investigated technology choice for $CO2$ emissions control and demonstrated that nuclear power is a risky choice due to the volatile lead-time. It entails the risk of failure of CO2 emissions control within the time limit set up in the COP3.

It also demonstrates that technology portfolios that combines nuclear power and new energy, reduce the risk due to the predictable lead-time of new energy power plant development.

New energy, however, increases the cost of power generation and CO2 emissions control. To shed light on the trade-off between cost-effectiveness and risk reduction, the investigation developed a framework to incorporate uncertainty into technology choice. It demonstrated that technology portfolios reduce the risk in a number of different ways. When nuclear power plant development has a modest or relatively high probability, technology portfolios enhance most effectively the probabilities of CO2 emissions control. However, they reduce a relatively small amount of CO2 emissions. So, the marginal cost of reducing CO2 emissions is relatively high. On the other hand, when nuclear power plant development has a relatively low probability, technology portfolios slightly improve the probability but reduce CO2 emissions most effectively. Hence, the marginal cost of reducing CO2 emissions is relatively low.

Profits are sensitive to the cost of new energy but virtually insensitive to the penalties of CO2 emissions. The gap in cost between new energy power generation and nuclear power generation is the predominant source of the trade-off.

5. POLICY CHOICE

This chapter discusses policy choice for CO2 control. It begins by analyzing how the utilities choose an optimal technology portfolio. It shows that the optimal technology portfolio depends on CO2 control policy. Then, it analyzes the basic interactions between CO2 control and the deregulation of the utilities. It shows that the presence of certain policies can harmonize CO2 control and deregulation. Finally, it proposes a tradable certification system for new energy power, which would both ensure technological change and market-competition.

5.1 OPTIMAL TECHNOLOGY PORTFOLIO

Chapter 4 demonstrates the trade-off between cost-effectiveness and risk in a quantitative fashion. But it does not state which of the optimal technology portfolios to choose. This section analyzes how the utilities choose an optimal technology portfolio, depending on the relative importance of cost-effectiveness and risk reduction. For the utilities, there are three criteria for technology choice: CO2 control, economy of power generation, and CO2 abatement.

<u>CO2 Control</u>

For CO2 control, the predominating factor is the enhancement of system probability that all projects necessary for CO2 control are completed no later than 2011. The COP3 set up certain legally-binding targets for greenhouse gas emissions. Japan must to reduce them to 6% below 1990 levels. Therefore, when CO2 control becomes a legal obligation for the utilities and requires them to build 20 "carbon-free" power plants to control CO2 emission, the purpose of a technology portfolio is to improve the system probability. In such a case, the optimal portfolio is to launch 3 or more additional projects for new energy power.

<u>Economy of Power Generation</u>

For the economy of power generation, the predominating factor is the profit in power generation. Because profit is often uncertain, there are some sub-criteria for technology choice: to maximize the expected mean value of profit, to maximize the maximum possible profit, to maximize the minimum possible profit, and to minimize the maximum gap between the maximum and the minimum possible profit. Because new energy projects narrow the dispersion of possible profit, the minimum possible profit increases. In most cases, however, new energy projects reduce the mean profit more substantially than they narrow the dispersion. For this reason, the minimum profit without a new energy power project is greater than that with one or more new energy power projects. To conclude, no matter what sub-criterion is applied, the optimal portfolio is to launch no new energy projects.

The reason behind this conclusion is the fact that the cost gap between new energy and nuclear power is greater than the cost of purchasing make-up electricity and the penalty for emitting CO2. For all practical purposes, the essential finding is that neither emission charges nor subsidies give any incentive to introduce new energy power. Unless there is an extremely high penalty imposed, nuclear power is more cost-effective than new energy power, even taking risk into consideration.

CO2 Abatement

For this criteria, the optimal portfolio depends on how much the utilities are willing to, or are able to, pay for CO2 abatement. For instance, when the utilities voluntarily reduce CO2 emissions, the optimal quantity of CO2 abatement depends solely on utilities' willingness to do so. When the utilities have other options to control CO2 emission, such as joint implementation and emission permit trade, the optimal portfolio would be to equalize the marginal cost of CO2 abatement with those of the other options. In such a case, the equalized marginal cost is the maximum the utilities can pay for new energy power generation.

In summary, the optimal portfolio depends on the relative importance between cost-effectiveness and risk. That importance, in turn, depends on CO_2 control policy. When building "carbon-free" power plants becomes a legal obligation for the utilities, the predominating factor is to enhance its probability. In contrast, economic incentives such as emission charges and subsidies give no incentive to reduce risk or introduce new energy. When the utilities have several options to control CO2 other than new energy, the optimal portfolio equalizes the marginal cost of CO2 abatement and other options.

5.2 INTERACTION BETWEEN CO2 CONTROL AND DEREGULATION

Section 5.1 demonstrates that the optimal technology choice depends on CO2 control policy. CO2 control policy, in turn, is closely interrelated with the deregulation of the utility industry. First, the goal of deregulation is to reduce the price of electricity. Low prices, however, promote high consumption and, consequently, CO2 emission. Second, cost minimization in a price-competitive market may squeeze out technologies that are beneficial to CO2 control but not as cost-competitive. Third, emission control may be a barrier to entry into the utilities market because it increases the cost of power generation while decreasing the demand and, consequently, the profit, of power generation. Fourth, the existing utilities are almost exclusively responsible for the development of nuclear power plants. A nuclear-leaning policy lays the obligation to control CO_2 on existing utilities, leaving the obligation of other power producers vague. The unfairness of the policy not only discourages the efforts of the utilities to reduce CO2 emission but also disturbs fair competition in the utility market.

For these reasons, CO2 control policy should not only balance the trade-off between cost-effectiveness and risk but also remain consistent with deregulation. To this end, the following part of this section analyzes the basic interactions between CO2 control and deregulation. The focus of the analysis is the effect of price and technological change on CO2 emission.

Deriving the Effect of Price and Technological Change on CO2 Emission.

The goal of deregulation is to reduce the price of electricity because the prices of monopolized utilities are higher than market prices. Under current regulations, the amount of profit the utilities are allowed is calculated as a percentage of their expenditures. Therefore, cutting costs will have the adverse effect of reducing profits, and the utilities have an incentive to invest more in their facilities than is needed. This phenomenon, called the "Averch-Johson effect," raises cost above the competitive level (Averch, 1962). In fact, while Japan's utilities received competitive bids for new thermal power plants since the abatement of the Electricity Utility Industry Law in 1995, the average contract price is lower than the avoid costs of the utilities by 20-30%.

On the other hand, CO2 control increases the cost of power generation and the price of electricity. Thus, the actual change in price depends on both the cost of CO2 abatement and price-competition through deregulation.

In turn, the change in price affects CO2 emissions. When the price goes up, CO2 emissions decrease with the decrease of demand. When the price goes down, the demand increases. CO2 emission, however, depends on the change in CO2 intensity of electricity. When CO2 intensity is improved at the same time as a demand for electricity changes, CO2 emission can be reduced. The change in CO2 emission is derived in the following equations:

The amount of CO2 emissions can be obtained by multiplying the electricity production and the CO2 intensity:

$$E_0 = \eta_0 \cdot Q_0$$

$$E_1 = \eta_1 \cdot Q_1$$

where

E_0 = the CO2 emission without CO2 control and deregulation [t-Carbon]

E_1 = the CO2 emission with CO2 control and deregulation [t-Carbon]

η_0 = the CO2 intensity without CO2 control and deregulation [t-C/kWh]

η_1 = the CO2 intensity with CO2 control and deregulation [t-C/kWh]

Q_0 = the electricity production without CO2 control and deregulation [kWh]

Q_1 = the electricity production with CO2 control and deregulation [kWh]

The change in CO_2 emission can be obtained from the difference of the two. The electricity production of $\boldsymbol{Q_1}$, however, can be higher or lower than $\boldsymbol{Q_0}$, depending on the change in price. Similarly, the CO_2 emission of $\boldsymbol{E_1}$ also can be higher or lower than $\boldsymbol{E_0}$, depending on both the change in electricity production and CO_2 intensity.

$$\Delta E \equiv \eta_1 \cdot Q_1 - \eta_0 \cdot Q_0$$

where

ΔE = the change in CO_2 emission [t-Carbon]

The price elasticity of demand, $\boldsymbol{E_p}$ [-], is given as the ratio of the relative change in the demand, induced by a unit relative change in the price.

$$E_p \equiv \frac{p}{Q} \cdot \frac{\partial Q}{\partial p}$$

When the elasticity is integrated, the following equation is obtained:

$$\left(\frac{p_1}{p_0}\right)^{E_p} = \frac{Q_1}{Q_0}$$

where

p_0 = the price of electricity without CO2 control and deregulation [yen/kWh]

p_1 = the price of electricity with CO2 control and deregulation [yen/kWh]

When the equation is substituted in the change in CO2 emission, the following equation is obtained:

$$\Delta E = \eta_0 \cdot Q_0 \cdot \left[\alpha \cdot \left(\frac{p_1}{p_0}\right)^{E_p} - 1\right], \quad \alpha \equiv \frac{\eta_1}{\eta_0}$$

where

α = the ratio of CO2 intensity [-]

When ΔE is taken as zero, "*a break even point*," at which the CO2 abatement through the improvement of CO2 intensity is commensurate with the CO2 increase through the demand expansion, is obtained. That is, the lie line describes the condition where the improvement of CO2 intensity is offset by the demand increase.

$$\frac{p_1}{p_0} = \left(\frac{1}{\alpha}\right)^{\frac{1}{E_p}} \quad \text{: a break even point}$$

<u>The Price Elasticity of Demand for Electricity</u>

Nagata estimated the long-run price elasticity of demand for electricity in Japan (Nagata, 1995). Table 5-1 shows the results of the estimation. Bohi and Zimmerman estimated the price elasticity in the US (Bohi and Zimmerman, 1984). The US estimate reports a consensus short-term elasticity of -0.3 and a long-term elasticity of -0.2 for residential consumers. No consensus estimates for other sectors were reported. For residential consumers, the demand for electricity is more elastic in Japan than in the US. The primary reason is that the price of electricity in Japan is 1.2 to 2.4 times higher than that in the US. The results of Bohi and Zimmerman indicate that commercial and industrial sectors exhibit a more elastic demand for electricity in the US. By contrast, Nagata's results show residential consumers' demand is more elastic than other sectors in Japan.

Table 5-1 Long-term Price Elasticity of Demand for Electricity of Japan

	1994 [million kWh]	Elasticity [-]
Agriculture/Forestry	3,855	-0.1874
Fisheries	-	-
Mining,Manufacturing	2,331	-0.1470
Construction	1,228	-0.8814
Foodstuffs	23,854	n.a.
Textiles	10,311	-0.1442
Paper,pulp	32,866	-0.0420
Chemical	60,163	-0.0672
Ceramics	23,194	-0.1095
Iron, steel	79,121	-0.0371
Nonferrous metals	17,950	-0.0624
Machinery	73,101	-0.0655
Other industories	64,308	0.0672
Residential	227,280	-0.2481
Commercial	206,920	-0.1493
Passenger trasportation	20,071	-0.1321
Freight trasportation	1,256	n.a.
Sub total	847,809	
Weighted average		**-0.1289**

Source: Nagata,1995 and JEA, 1996

Effect of Price and Technology Change on CO2 Emission

Figure 5-1 shows the effects of the change in CO2 intensity and the price on CO2 emissions. For simplicity sake, elasticity is assumed to be the weighted average of sectors. The vertical axis indicates the change in price. When the cost of CO2 abatement is higher than the cost reduction through market competition, the price of electricity goes up. By contrast, when cost reduction through deregulation is greater than the cost of CO_2 abatement, the price goes down.

The horizontal axis indicates a ratio of CO2 intensities, which represents the change in CO2 intensity. In other words, it represents a technological change in power generation in terms of CO2 control. When "α" is equal to 1, either no technological change takes place in power generation, or technological change is offset by the expansion of such carbon-rich fuel burning power generation as coal.

A solid line represents a break even point. By definition, CO2 emission does not change on the line. In the area above the line, CO2 emission increases. In the area below the line, it decreases, particularly, in the area, "**W**," where both CO2 emission and price decrease thanks to technological change and market competition. Therefore, the area of "**W**" represents a win-win situation for CO2 control and deregulation.

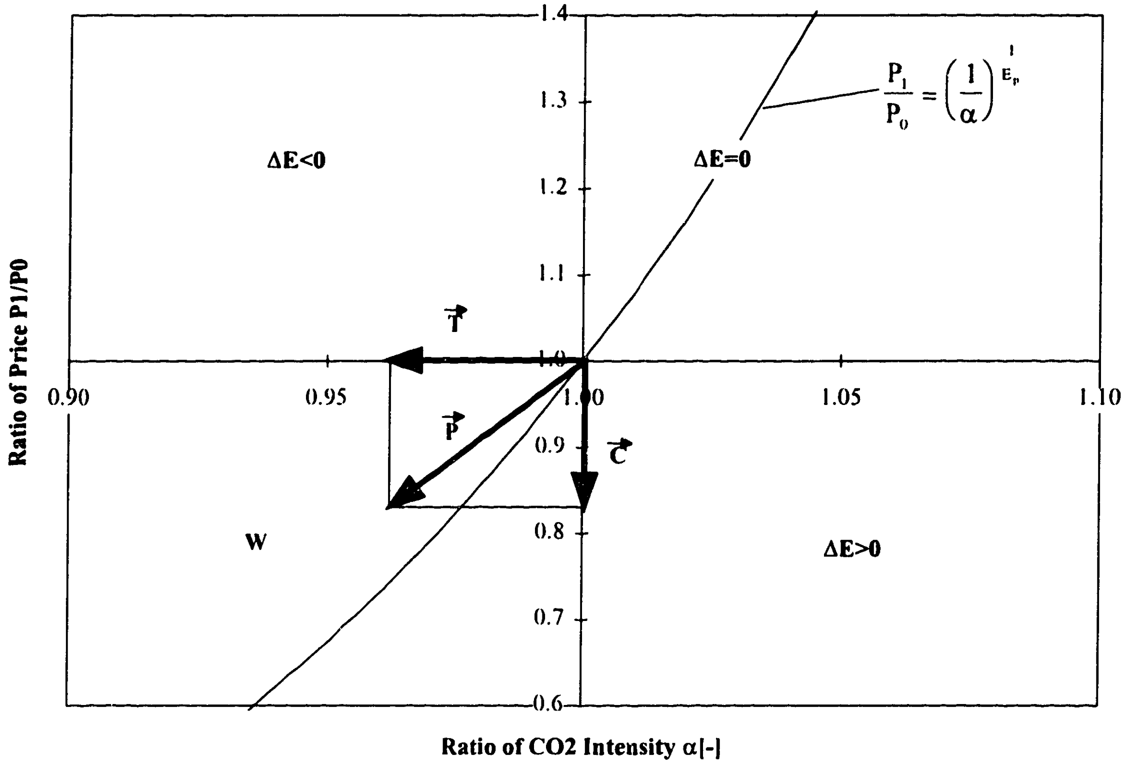


Figure 5-1 Effect of Price and Technological Change on CO2 Emission

Policy Implications

For policy choice, the most important finding is that CO2 control policy should consist of two "policy vectors;" technological change and market-competition. Arrows in Figure 5-1 shows the graphic concept of policy vectors. The origin represents the current condition. The first vector is technological change, "$\vec{T}$," where improved CO2 intensity is a result of enforcement or enhancement of technology changes. The second one is market-competition, "$\vec{C}$," in which the price of electricity is driven down through price-competition. The third vector is the policy to be adopted, "$\vec{P}$," which is the result of "$\vec{T}$" and "$\vec{C}$." Figure 5-1 theoretically confirms the presence of the policy vector, "$\vec{P}$", which harmonizes CO2 control and deregulation.

For instance, the average, which is the quotient of total revenue by total power generation, is 18.81 yen per kWh (15.7 [cent/kWh]). On the other hand, avoid costs, which the utilities have announced in past bids, range from 9 ~ 17 yen per kWh (8-14 [cent/kWh]), depending on types of power sources. The cost of base load is lowest thanks to utilization rates as high as 70%, while that of peak load is highest due to utilization rates as low as 10%.

Assuming that the average avoid cost is 14 yen per kWh, this roughly accounts for 75% of the electricity price. Contract prices in past bids are lower than avoid costs by 20% ~ 30%. In a competitive market, price is equal to marginal cost. Consequently, assuming that the contract prices are equal to the marginal cost of power generation, the price of electricity should be reduced by 15% ~ 20%. The MITI is expecting that deregulation reduces the price by up to 20%. A reduction of 20% is roughly equal to the results of past bids. In that case, CO_2 intensity should be improved by 1% ~ 2% in order to stabilize CO_2 emission at the current level. In other words, without any improvement in CO_2 intensity, CO_2 emission will increase. Similarly, without market-competition, the price will go up when CO_2 control is enforced. For this reason, CO_2 control policy should promote technological change and market-competition simultaneously.

5.3 TRADABLE CERTIFICATE OF CARBON-FREE POWER GENERATION

This section integrates technology choice with policy choice and proposes CO2 control policy as the ultimate recommendation of this thesis. The central issues of technology choice and policy choice can be summarized as follows:

- Nuclear power is a cost-effective but risky option due to the volatile lead-time. The risk is not negligible and reducing the risk is indispensable for CO2 control.
- Technology portfolios, which combine nuclear power and new energy power, reduce the risk as a result of the predictable lead-time of the latter. However, the trade-off for reducing risk is increasing cost.
- Because of the large cost gap between nuclear power and new energy power, economic incentive has little effect in the effort to introduce new energy power. Their binding introduction is necessary for ensuring CO2 control.
- The binding introduction, however, should be consistent with deregulation and vice versa. Theoretically, the two can be harmonized as CO2 control policy promotes introduction and deregulation at the same time.

In the final analysis, the issue to be addressed is how CO2 control policy can simultaneously ensure new energy power and market-competition. As analyzed in Section 5.2, they are closely related and at times can conflict. The conflict is produced when new energy power raises the cost of power generation, reduces the profit, establishes a barrier to entry into a market, and stifles market-competition. Therefore, if the introduction of new energy power generation becomes profitable for ventures, it will encourage, as well as reduce the cost of, entrance into the market, promote market-competition, all the while decreasing the cost of electricity.

In short, the key for successful policy is to create a profitable market for new energy power generation. The weakness of the current policy is that it provides incentives for "cost reduction" but allows little chance for "revenue generation." Solar power is an instance, where, through government subsidy, incentive is provided to use an alternate form of power in order to reduce the cost of electricity. Subsequently, the price of electricity goes down, and the incentive to reduce costs decreases. In such a case, the government is required to increase the subsidy in order to maintain incentive. As a result, the solar power market will never privatize or expand. To correctly promote the new energy market, there has to be a more tangible incentive and a much higher return than simply reducing expenses. Motamen-Scobie points out:

> For new investment, there is a tendency within industry to favour 'revenue generation' projects against those for 'cost reduction' by requiring shorter gestation and payback periods for the latter, even though the former is the dual of the latter. Thus, energy efficiency projects tend to receive low priorities by industry by requiring much higher return and faster payback periods for them—sometimes as low as three months. It is possible that a supply shock may need to occur to induce the market to invest and develop the required technology in order to redress some of the current environmental imbalance. (Motamen-Scobie, 1993)

One workable policy would be the creation of effective demand while introducing competition into the market. The American Wind Energy Association proposes the Renewable Portfolio Standard (RPS) and several states are now preparing RSP legislation. RSP bills are also proposed at the federal level (Table 5-2 and Table 5-3). Although the RSP was originally proposed to ensure the utilization of renewable energy, it could serve this purpose as well. The AEA defines the RPS as:

> Renewable Energy Credits, or "RECs." are central to the RPS. A REC is a tradable certificate of proof that one kWh of electricity has been generated by a renewable-fueled source. RECs are demonstrated in kWh and are a separate commodity from the power generation itself. The RPS requires all electricity generators (or electricity retailers, depending on policy design) to demonstrate, though ownership of RECs, that they have supported an amount of renewable energy generation equivalent to some percentage of their total annual kWh sales. For example, if the RPS is set at 5%, and a generator sells 100,000 kWhs in a given year, the generator would need to possess 5,000 RECs at the end of that year. (AWEA, 1997)

The objective of this policy is to ensure a minimum level of renewable energy in a way that also promotes competition within the renewable energy industry. Under the RPS, the utilities either produce electricity from renewable energy by themselves, buy it from others, or buy RECs from others (renewable power producers and REC brokers). This market-based approach would allow the RPS to be met in a cost-effective way. Government involvement would be limited to monitoring purchasing RECS, as well as setting initial market regulations.

The RPS would maintain competition among renewable power producers, rather than an initial one-time bidding competition. Thus, it encourages power producers to continue efficiency improvement efforts. RSP's major benefits are that it can: (1) guarantee the amount of renewable energy introduction, (2) increase the economic efficiency of the introduction, (3) maintain a neutral position among existing utilities and independent power producers, and (4) create an effective demand for renewable energy technologies, which would promote technological change, cost reduction though market-competition, economy of scale and learning-effect.

The same argument generated by the RPS holds true for new energy using the stated definitions for "New Energy Credits (NECs)," or "Carbon-Free Energy Credits (CFECs)." The main problem with CO2 control is that it is quite impossible to introduce new energy into a market without a binding obligation. The New Energy Portfolio Standard (NEPS) or the Carbon Free Energy Portfolio Standard (CFEPS), which is the same certification tread system as the RPS, can guarantee the amount of new energy introduction and ensure CO2 control.

In addition, the NEPS or CFEPS could encourage new ventures to enter the utility market. This is through the creation of effective demand in a situation where existing utilities have little price-competitiveness in new energy power generation. For instance, the Tokyo Electric Power Company, Japan's leading utility company, has carried out projects with wind power generation. The costs of their projects are 43 ~ 46 yen per kWh (36 ~ 38 [cent/kWh]) (TEPCO, 1997). In contrast, a small venture company, Yamagata Wind Power Generation Research Center CO., operates wind power plants of 400 kW. Though these plants are located in an area with relatively low-wind, the cost of their plants is only 9 ~ 12 yen per kWh. Private capital was awarded by the Agency of Natural Resource and Energy for this venture (NEF, 1998). This example suggests that new energy market can indeed be profitable for new ventures.

In summary, the NEPS or the CFEPS involve two policy vectors; market-competition "$\vec{C}$," technological change "$\vec{T}$." Since they ensure market-competition and technological change at the same time, they realize the win-win situation where CO2 control and deregulation are harmonized and cost-effectiveness and risk reduction are balanced.

Table 5-2 RPS Employed by US Regulatory Authorities

Adopted By	Renewables Requirement	Note
Arizona Corporation Commission	0.5%; takes effect in 1999, increasing to 1% in 2002	Solar only. Will create a 120-MW market for solar by 2002
Maine Legislature	30%; takes effect in March 2000	
Nevada Legislature	2/10ths of 1% rising to 1% by 2009. Takes effect January 2001	Half of the renewables must be derived from solar resources.
Massachusetts Legislature	Begins at existing levels as early as 2000; grows by 1% in 2003 and 1/2% per year thereafter to 2009.	Increased levels must be supplied by new resources, including advanced biomass, landfill gas, wind, solar, geothermal or ocean technologies.

Source; AWEA 1997

Table 5-3 RPS Shares Proposed in electricity deregulation Bills before Congress

Bill #,			**Renewables Requirement ***					**Notes**
Author	2000	2001	2003	2005	2008	2010	2020	
S.237 Sen. Dale Bumpers (D-Ark.)	-	-	5%	5%	9%	9%	12%	Requirement rises to 12% in 2013. Large hydro eligible. Applies to retailers.
S. 687 Sen. Jim Jeffords (R-Vt.)	2.5%	3%	4%	5%	8%	10%	20%	Increases 1/2% per year to 2005, then 1% per year to 2020. Hydro not eligible. Applies to non-hydro generators.
H.R. 655 Rep. Ed Markey (D-Mass.)	3%	-- increases gradually --				10%		3% requirement begins in 1998. DOE instructed to increase requirement gradually to 10%. Hydor not eligible. Applies to generators.
H.R. 655 Rep. Dan Schaefer (R-Colo.)	-	2%	2%	3%	3%	4%		Hydro not eligible. Applies to non-hydro generators.

* Non-hydro renewables currently supply about 2% of the US power.

Source; AWEA 1997

6. CONCLUSIONS

This thesis has considered both technology choice and policy choice for CO2 control of Japan's utilities. For technology choice, nuclear power is the main component of Japan's utilities. Nuclear power is the least-cost technology for power generation and CO2 control in resource-poor Japan. However, lead-time is long and volatile due to difficulty in siting new power plants. Because the COP3 set up the timetable for CO2 control, CO2 control must be implemented within a given time period. However, with such a long and volatile lead-time, implementation within the established timetable risks failure.

For policy choice, CO2 control has the potential to conflict with deregulation of the utility industry. Due to the heavy costs of emission control, a barrier to entry into the utility market is established. In contrast, deregulation increases demand and, consequently, CO2 emissions. A nuclear-leaning policy discourages the efforts of the utilities to reduce CO2 emission, and disturbs fair market-competition.

For these reasons, technology choice and policy choice should cope with the trade-off between cost-effectiveness and risk and the conflict between CO2 control and deregulation simultaneously. To this end, this thesis has developed and demonstrated a framework in order to illuminate the possibilities. A financial economic analysis has been applied to technology portfolios of nuclear power and new energy power. Then, it analyzed the conflict between CO2 control and deregulation in terms of prices, technological changes, and CO2 emissions. Finally, it has proposed a tradable certification of carbon free energy power generation such as new energy in CO2 control. Among the main findings were:

- **It is possible that the risk of nuclear power plant development is not negligible. The risk strongly depends on the most risky project.** The basic statistics show that nuclear power projects need to have a probability of more than 0.97 to commission 20 plants not later than 2011 with a probability of 0.8. There is no concrete evidence, but considering the plight of ongoing projects as well as past records, the probability of 0.97 is not viable. When the probabilities of each project drops to 0.9, the probability of 20 plants being commissioned diminishes to 0.5. Thus, it is safe to say that reducing risk is indispensable for ensuring CO2 control.

- **Technology portfolios of nuclear power and new energy power reduces the risk of failing to control CO_2.** New energies such as wind power have less difficulty in siting new plants than nuclear power. Their lead-time is more predictable than that of nuclear power. For this reason, new energy power enhances the probability of CO_2 control and reduces expected CO_2 emissions.

- **Technology portfolios reduce more effectively risks in moderate-probability conditions and expected CO_2 emissions most greatly in low-probability conditions**. New energy projects have different effects on risk reduction and CO_2 reduction. The relative importance of them, however, depends on CO_2 control policy.

- **The trade-off between cost-effectiveness and risk arises mainly from the cost gap between nuclear power and new energy power. Economic incentive has little effect in introducing new energy power**. The formation of new energy is most sensitive to profit, while the sensitivity to penalty is negligible. This is because the cost gap is greater than the cost of delay in plant development. Therefore, economic incentives such as subsidies and penalties have little effect in introducing new energy power.

- **Technological change and market-competition can harmonize CO_2 control and deregulation.** The analysis of the interactions among the two policies demonstrates that CO_2 control and deregulation can be harmonized. In contrast, technological change without market-competition raises costs while market-competition without technological change increases CO_2 emission.

- **A tradable certificate of new energy power generation ensures both technological change and market-competition so that CO_2 control and deregulation can be harmonized**. The key for the successful introduction of new energy power is to create a profitable market for it. A tradable certificate creates the effective demand in competitive markets. The demand, paired with market-competition reduces the cost through price competition, economy of scale, and learning-effect. At the same time, because the certificate system ensures the presence of new energy, it enhances CO_2 control. Setting the appropriate standard for the certificates balances the trade-off between cost-effectiveness and risk.

Although the analysis assumed that there is no risk involved with new energy, the methodology developed in this thesis can apply to any combinations of technology options as long as the risks and the costs are determined.

In addition, the methodology tacitly assumed one-for-all decisions in order to demonstrate clearly the implications of technology portfolios. In practice, it can be applied to dynamic strategic planning, which consequently makes decisions in response to the outcomes of previous decisions. Because the lead-time of new energy power plants is shorter than that of nuclear power, the decision to launch new energy projects can be postponed until the delay of nuclear projects is sufficiently clear. For instance, due to the 8-year time frame for actual construction, the utilities would have to begin construction of nuclear power plants at latest 2004. At that time, the utilities can determine the number of new energy plants which would need to be built in response to the number of nuclear plants which would not be able to go into operation by 2011. As of yet, there are few studies about a tradable certificate system in Japan (Sagawa, 1998). However, considering time constraints, Japan is probably considering the introduction of the system before 2004.

APPENDIX

Under a long-term contract, the output of individual nuclear power projects depends on both the number of plants commissioned, and the history of plant development. Figure A-1 shows the event tree of a long-term contract case. When no nuclear power project is commissioned in the year 2006, a long-term contract is held. Because 6 nuclear power projects are completed with a project probability of $\boldsymbol{F_{2006}}$, the probability that a contract being held, $\boldsymbol{P_{12}}$, is obtained as:

$$P_{12} = \left(1 - F_{2006}\right)^6$$

Consequently, the probability that no contract being held, $\boldsymbol{P_{11}}$, is obtained as:

$$P_{11} = 1 - P_{12}$$

In the year 2007, there are four cases. First, when at least one project is completed in the year 2006 and at least two projects are completed in total in the year 2007, no contract is held in the year 2007 ($\boldsymbol{P_{21}}$). Second, when one project is completed in the year 2006 and no additional project is completed in the year 2007, one contract is newly held in the year 2007 ($\boldsymbol{P_{22}}$). Third, when no project is completed in the year 2006 and at least one project is completed is completed in the year 2007, one contract is continuously held in the year 2007 ($\boldsymbol{P_{23}}$). In that cast, even when more than two projects are completed in the year 2007, the contract held in the year 2006 is not canceled. Fourth, when no project is completed in the years 2006 and 2007, two contracts are held.

The probability of $\boldsymbol{P_{22}}$ is obtained by multiplying the probability that one project is completed in the year 2006 and the probability that the remaining five projects are not completed in the year 2007:

$$P_{22} = \left[{}_6C_1 \cdot F_{2006} \cdot \left(1 - F_{2006}\right)^5\right] \times \left(1 - Y_{2006}\right)^5$$

The probability of the remainder of the projects being completed in the year 2007 is obtained as the ratio of the difference in a project probability in the years 2006 and 2007 to that of 2006:

$$Y_{2006} = \frac{F_{2006} - F_{2007}}{F_{2006}}$$

The probability of P_{21} is obtained from the difference between P_{11} and P_{22}:

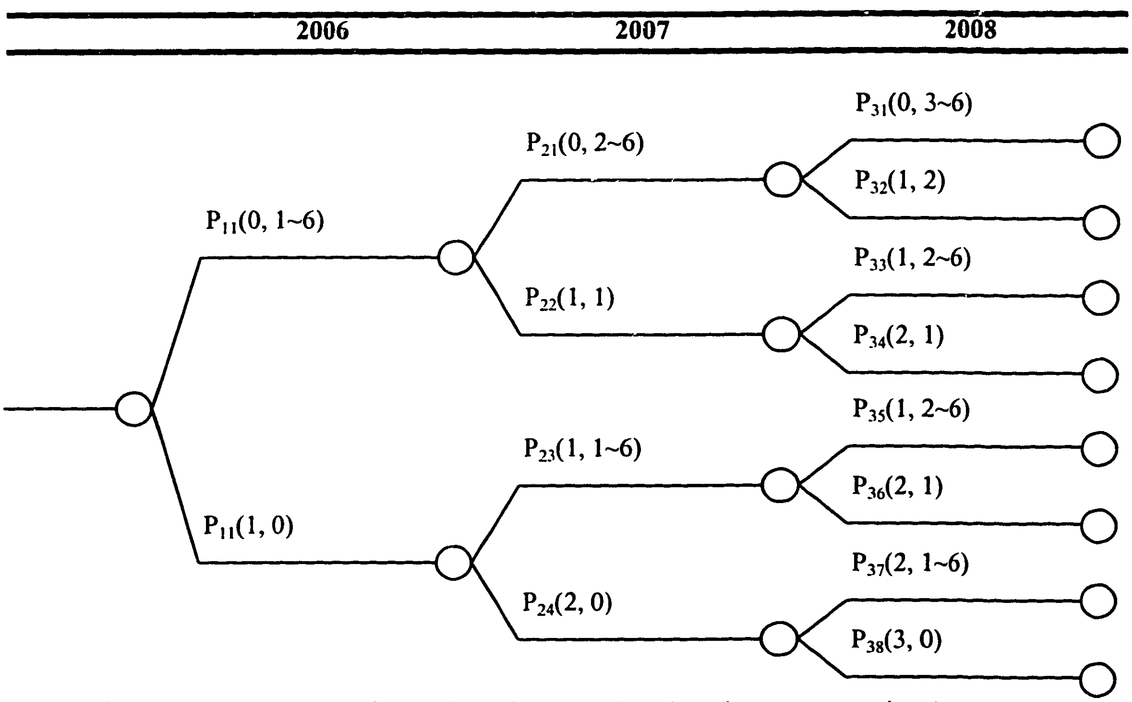
$$P_{21} = P_{11} - P_{22}$$

Similarly, the probabilities of the other cases are obtained as:

$$P_{24} = \left(1 - F_{2007}\right)^{6}$$

$$P_{23} = P_{12} - P_{24}$$

Therefore, the sum of P_{21}, P_{22}, P_{23}, and P_{24} is equal to 1 and the probability of one contract being held is obtained by summing P_{22} and P_{23}. Table 7-1 shows the summary of the procedures and Table 7-2 shows the probabilities of long-term contracts in three scenarios.



(m, n)=(the number of contracts, the number of commissioned nuclear power projects)

Figure A-1 Event Tree of Long-term Contracts

Table A-1 Probabilities of Long-term Contracts being held

	t		
	2006	2007	2008
$P_M(0, t)$	P_{11}	P_{21}	P_{31}
$P_M(1, t)$	P_{12}	$P_{22}+P_{23}$	$P_{32}+P_{33}+P_{35}$
$P_M(2, t)$	0	P_{24}	$P_{34}+P_{36}+P_{37}$
$P_M(3, t)$	0	0	P_{38}
$P_M(4, t)$	0	0	0
$P_M(5, t)$	0	0	0
$P_M(6, t)$	0	0	0
$P_M(0, t)$	0	0	0

Table A-2 Results of Probabilities of Long-term Contracts being Held

		t					
		2006	2007	2008	2009	2010	2011
	$P_M(0, t)$	0.8297	0.7067	0.6110	0.5197	0.4047	0.2438
	$P_M(1, t)$	0.1703	0.2449	0.2892	0.3262	0.3703	0.4178
	$P_M(2, t)$		0.0484	0.0898	0.1292	0.1784	0.2541
Optimistic	**$P_M(3, t)$**			0.0100	0.0234	0.0416	0.0729
	$P_M(4, t)$				0.0016	0.0047	0.0106
	$P_M(5, t)$					0.0002	0.0008
	$P_M(6, t)$						0.0000
	$P_M(0, t)$	0.4751	0.2499	0.1416	0.0809	0.0409	0.0167
	$P_M(1, t)$	0.5249	0.4483	0.3428	0.2601	0.1869	0.1193
	$P_M(2, t)$		0.3018	0.3733	0.3672	0.3393	0.2908
Moderate	**$P_M(3, t)$**			0.1422	0.2363	0.2955	0.3337
	$P_M(4, t)$				0.0555	0.1191	0.1845
	$P_M(5, t)$					0.0183	0.0498
	$P_M(6, t)$						0.0052
	$P_M(0, t)$	0.2008	0.0494	0.0143	0.0044	0.0013	0.0004
	$P_M(1, t)$	0.7992	0.3120	0.1215	0.0522	0.0224	0.0097
	$P_M(2, t)$		0.6386	0.4057	0.2210	0.1158	0.0552
Pessimistic	**$P_M(3, t)$**			0.4585	0.4281	0.3144	0.2093
	$P_M(4, t)$				0.2943	0.3769	0.3537
	$P_M(5, t)$					0.1693	0.2839
	$P_M(6, t)$						0.0878

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